ALASKA STATE LEGISLATURE

SPECIAL SESSION

THE ALASKA GAS PIPELINE

MAY 18, 2006

9:00 a.m.

Taken at:
Centennial Hall
Juneau, Alaska

Reported by: Sandra M. Mierop, CRR, CCP

PROCEEDINGS

COMMISSIONER CORBUS: Would everybody please take their seat so that we can get going?

Thank you.

Good morning. Welcome to Day 7 of the presentations on the Alaska gas pipeline proposed contract.

Today's program will consist of a series of presentations on the explanation of the contract provisions. We started that process yesterday afternoon.

Our presenters will be Bob Loeffler, who you heard from yesterday afternoon, and Dan Dickinson, who's not with us yet, but he will be shortly.

Also present on the dais is -- is Alan Birnbaum from the Attorney General's Office. We're going to take two breaks this morning. Two ten-minute breaks.

I ask you to submit your questions in writing, and we will try to answer the questions as we finish up with the particular set of topics.

The first topics are primarily

related to regulatory issues that Bob Loeffler will lead us through. And we look forward to your questions.

Mr. Loeffler.

MR. LOEFFLER: Good morning, everyone. I want to explain the layout of the day. It's going to be a little bit of a tennis match between Dan Dickinson and myself.

I'm going to go through Articles 8 and 9 and start the -- the fiscal articles with Article 11.1. Then Dan will pick up for a couple hours. Then, in the afternoon, if it goes according to plan, I will finish off the contract, and Dan will continue with various fiscal discussions.

I want to add to one answer yesterday or two answers.

There was a question yesterday about why shouldn't there be common carriage regulation of the pipeline as opposed to contract carriage. And I gave -- everything I said yesterday is correct, in my view.

But I was reminded of something that in the open season, if there are more bids for capacity than there is available capacity, there is a element of the open season rules that resembles common carriage. And that is, there is prorationing of capacity, meaning everyone's bid for capacity is reduced so the total number of bids fit the capacity. And if there are anchor shippers, they get sort of -- they get prorationed. The idea is that there is some sort of balancing of bids at that time. But the open season regs speak for themselves.

The second point is that -- I haven't mentioned this, and it's not part of the contract. But there will be this executive branch appointment of the federal government, a federal coordinator whose job will be to get all the permitting done, coordinate the many federal agencies, and there's a duty imposed on those federal agencies by Section 104(b) of the October 2004 legislation to -- for the agencies to cooperate with FERC as the lead agency in carrying out their responsibilities.

One note on this sort of Washington angle on this, there was a fight in the legislative process in the federal government as to whether the Department of Interior or the FERC would be the lead agency, and the FERC prevailed.

But those issues probably will re-emerge.

Now, on to regulation and access and disposal.

This -- I thought this little schematic is useful. If you look at sort of the basic layout, you'll see that there is, as we described, the pieces of the project, and then there's the potential for a lateral to Anchorage or the Anchorage area. That lateral is not part of the defined project under the contract, meaning the sponsors don't want to have the responsibility for building that. So it's not part of the contract. It's free for anyone to build who wants to step up to the plate on that.

And it actually, in the legislation that went through Congress, under Section 101.8(a), it's careful that -- carefully defined that the FERC does not have jurisdiction over that lateral. The RCA has that jurisdiction, because that lateral is defined as a section 1(b) distribution company under the Natural Gas Act.

So, that, the RCA will regulate, set the rates of, et cetera.

Now, in thinking about all the regulatory issues, and I know this article deserves a lot of discussion and will receive a lot of discussion, you have to go back to sort of what the overarching goals are of the project.

The Stranded Gas Act and also the fiscal contract are designed to provide as much certainty and clarity as you can achieve. That's a way of eliminating cost and delay on the project.

And so when we sat down to work on these regulatory articles, we had interests that want -- we wanted respected and preserved. And similarly the project sponsors would say, well, yeah, the law is this, but there could be disputes. Disputes add to delay, even if your view of the law is entirely correct. Can't we do something to achieve a greater measure of clarity and certainty?

And that goes behind a lot of what you'll see in Section 8.

In addition, I think you should look at both Section 102.2 of the October 2004 legislation, which defines the project for purposes of the federal legislation. And there's a corresponding definition of "the project" in the contract. And that ties to that Article 4 that we looked at yesterday.

And then in 108(a) -- I can't read my handwriting right, it might be 108(c) of the October 2004 legislation, it says the Commission shall establish -- the Commission in this case is the FERC -- rates for the transportation of Alaska natural gas on the project.

Another way of thinking of it is the project is everything that you see on the screen, except the lateral line down to Anchorage.

Now, here we go. The first clause of 8.1 -- or 8 is 8.1 which really sets forth the parties' expectations. And that's all it is, a set of expectations, and it divides between the part in Canada and the part in Alaska that there will be regulation under the pertinent statutes for the Alaska part and under the pertinent Canadian law for the Canadian part.

You may ask what about the -- if federal law does not apply. And the answer on that is thinking that this contract would last a very long time, the sponsor group companies said, well, isn't it possible that FERC would reverse its position on jurisdiction on some issue, and then where will we be?

I've lived a long time with the Natural Gas Act, which has been amended over the years. I -- and the case law, and I think that's a remote possibility, but it's one we've covered by the commercial agreement language.

And then 8.2, which says the parties shall be unified in supporting FERC jurisdiction in their positions before the agencies and will not seek to add to that jurisdiction or change it.

And here's where we get into some interesting discussion. I've said yesterday, and I'll repeat today, that as we analyze the project for the reasons I just gave and the reasons I gave yesterday, that the RCA, we believe, consistent with the case law and the statutes, does not have jurisdiction over an interstate gas line and the pipelines that feed into it, including the treatment plant.

And this -- this clause was first discussed in December, 2004 and was settled in -- somewhere around -- well, March, 2006. That's how much discussion it took.

Frankly, we saw -- I saw, at least, no reason to put language in about the RCA. The sponsor group companies were very insistent that they have clarity on this point. And it was settled at a -- at a principled level as part of a trade on commercial terms that was made in, I believe, December 2004 at a very high level of both the companies and the State.

And Jim Clark is going to get into that process in the process of trades next week when he comes before you.

So let me go on and, acknowledging that the trade was made there, let's talk about what exactly happens under this clause.

If the RCA found a way to assert jurisdiction over the project -- and -- and you ask, How could that be if it's so clear? Well, I can give you a theory, and I will. Then it would take time to resolve the issue of does it or does it not have jurisdiction.

If you look at some of the state regulatory statutes, there is a possibility that the RCA might, through the right of way leasing statute, say that it has jurisdiction over the portion of the gas that's destined for intrastate markets.

As I said yesterday, that is

inconsistent with the Supreme Court ruling in the Lavaca case, and also inconsistent with the fact that if push comes to shove the holder of a Certificate of Public Convenience and Necessity could condemn a right of way.

So -- but recognizing that someone might think of that argument, it would end up in a dispute which could take considerable time to resolve. And time is the enemy of this project.

So, thinking of that, we came up with this language. If -- if the RCA attempted, I think contrary to law to assert jurisdiction, then the parties would work together and try and find the solution to that problem.

If you go to the next page, and I'll come back to this page for a moment, but under the dispute resolution mechanism of the contract, nothing can happen for nine months in terms of pursuing an issue of loss. That gives people time to work on solutions, talk to the RCA about the problem, statutory amendments, if that were desirable, litigation if that were desirable.

But, if at the end of the nine months a participant believes -- a participant is one of the oil companies -- believes there had been a loss, then you go to the dispute resolution process.

And here you've got to think about what would be the claims that might arise and how those claims are limited by the contract.

Loss is a defined term, and it is broadly defined because it's both used in favor of the State and against the State in the contract.

But if you turn to page 212 of your contract in bold-faced type, just like in a commercial lease or something, it says: In no event is any party liable to any other party for the following loss that arise or -- out of or relate to this contract or any breach of it: Any consequential or incidental damages, including lost profits or any special or punitive damages; a party shall neither claim nor, if awarded, collect any prohibited loss from any other party in any proceeding in any dispute.

So, if the RCA asserted jurisdiction, there's some further conditions, and the parties claimed a loss, or the participants claimed a loss, then, in that event, if you got over all the hurdles, you still could not get lost profits. So, if they said that the throughput had been declined because part had been diverted or prorated or whatever, even though I don't think those claims stand under federal law, you can't get lost profits, you can't get consequential damages, you can't get the incidental damages.

So what are the hurdles you have to get over even before you get to the claim of loss? If the RCA asserts jurisdiction and then takes actions that are inconsistent with FERC principles for jurisdictional facilities or in the remote event their commercial agreements with those agreements that result in a loss, so you -- you would be litigating the issue of whether it was consistent or inconsistent with FERC principles. And if you got over that hurdle and proved that it was inconsistent, then you would argue about what the loss might be.

And as you plumb to the companies on what they were concerned about, they were concerned about prorationing. They were concerned that the RCA might attempt to prorate capacity on the lines that fed into the mainline or even on the mainline itself.

I think such a prorationing would be a direct conflict and interference with the terms of access set by the FERC to the interstate pipeline, but that doesn't mean, at least in the companies' mind, that they might -- that this might not arise in a future FERC.

So, the result is they -- they would claim there was a loss. They would claim if no action were taken, that it would be inconsistent with FERC policy, and they would then get into the factual situation of was there really a loss. And from their point of view, that would include the cost of cover or transportation.

As you spin through the scenarios that might occur, and this is -- you get more and more out on the hypothetical chain. You run into: Could that include the cost of cover if gas were taken off in Alaska, would it leave gas -- it would require them to cover a contract downstream because they didn't have enough gas. Well the cost of cover at that time could either be to their benefit or their detriment, depending on what the price of gas is whenever this hypothetical could occur. So there might be no loss.

Anyway, it was, as I said, a much disputed clause, and we -- we built in a number of protections. I don't think it will ever be used, but I can't prove that it will never be used, and that is the sort of content of the RCA clause.

Moving on to the next point. Remember the State was participating in this new gas pipeline world in several ways. It will be an owner of a pipeline, but it also will be a shipper, because it will be marketing its own gas. As a shipper, we wanted to be sure that we could do what we've always done for 30 years at the FERC, which is intervene and pursue our claims that a tariff is too high, that the tariff is discriminatory, the tariff has some problems connected with it. So we wrote in affirmatively a clause, 8.4, that says: This contract does not affect the right of any party to petition FERC or NEB to institute a proceeding, participate -- remember, to institute, not merely to participate, to institute a proceeding to effect -- that involve the tariffs.

And as a member of the LLC, the state pipeline company will be bound by the actions of the LLC in putting forward a tariff. That will be discussed within the LLC. There will be an agreement on it, a vote on it, and then it will go forward as a proposal of the LLC. But the FERC can modify that. So the State will have a voice in how that tariff is proposed to the FERC through its LLC participation, and in a sense, it was of a second voice in a different capacity, as a shipper, in the process at the FERC.

And we wanted to be sure that just because we were a member of the LLC we were not bound in our shipping capacity in our rights to comment, challenge, protest, intervene on a tariff. And that's what 8.4 does.

8.6 is about previously used assets. And here's what the deal is. There are parts, particularly of the treatment plant, that will be used for -- well, let me change that. The gas treatment plant will include some facilities that already exist on the Slope, and we wanted to be sure that we were able to challenge if -- if the GTP LLC tried to put those plans into rate at a new cost, not the cost that reflects their sort of depreciated value, we wanted to be able to bring that issue to the FERC and also pursue FERC policy, whatever it will turn out to be on that carryover. The GTP will have a lot of new investment in it, too. It's not just carrying over the old. But we didn't want a writeup, if we could avoid it, of the assets -- the old assets that were put into the GTP.

Now, FERC has a number of cases and policies here. Going back to the oil pipeline area and the electric area, the FERC has consistently said, sustained by the D.C. Circuit, that you can't write up an asset merely on sale.

So that was the Williams -- the first time was the Williams case. So you take a regulated asset, you sell it from X to Y, and unlike an apartment building, you don't get a writeup on the asset in the hands of the new seller, so -- new buyer, excuse me. So, that's -- unless -- and now there is an unless -- there is some sort of benefit.

There is some other law that deals with assets that were not regulated coming into regulation, and what you do there, and there's tension between those two cases.

But we thought with this clause we had enough leeway if the LLC decides to seek a writeup on the used assets to fight that.

The seasonal variable capacity is just a nondiscrimination point. There may be extra capacity offered because of seasonal variations in the capacity of the pipeline. We want to be sure that was available to firm shippers -- State will likely be a firm shipper -- on a nondiscriminatory basis.

On to the favorite subject of expansion. And I apologize, but I'm going to repeat a little bit of what I said yesterday.

Expansion can occur in three ways. The new way, totally new in the law, was under Section 105 of ANGPA, as it's called, the October 2004, legislation. And if you look at that, there's sort of a careful dance that you go through with the FERC for that expansion capacity. I can't emphasize enough that this is the first time FERC has been given the authority to order expansion of an interstate pipeline. It does not have that authority under the Natural

Gas Act. And there's a lot of law affirming that it does not have that authority.

That legislation was carefully worked out as a compromise between, really, the producers and other Lower 48 interstate pipelines and potential shippers and explorers in Alaska and the state. So, when you -- when I say there's a careful dance in the legislation, that's the result of the compromise. There are various protections that are in it that are designed to make sure that expansion can occur on an economic basis and without detriment to the pipeline or existing shippers.

And when we came to discussing expansion in the negotiations, frankly, the companies said to us: What are you doing? You won. You got this novel right in the Federal statute. What more do you want, as long as it exists, that it will never be used because it's a backup. And we said, no, no, we want more than that, just as protection for unaffiliated parties.

I -- I will skip over the totally voluntary expansion by the owner.

A totally voluntary expansion is,

as I said yesterday, when the pipeline decides it's in its business interest to add capacity.

Now, just on a digression on how capacity is added. Capacity can be added in two ways on an interstate pipeline. One way is essentially in-fill compression. You add some more pump-up, some pumps, some compression to the pipeline, and that boosts what can go through.

The second more expensive way to expand the pipeline is to loop it, where you actually add, at particular sections, extended pieces of pipe. So you really have two pipes going down for periods of the -- during the length of the pipeline.

In-fill compression, adding pumps, is sort of the cheaper way. And my understanding is that the project provide -- is going to be designed to -- or has been designed, to the extent it has been designed, to be expanded through in-fill compression up to something like 5.7 or 6.0 bcf per day. And that's a lot of expansion of capacity, given, as I said yesterday, again, that there's an expectation that there's not enough gas. And, oddly, there are other parts of the contract that deal with how we get more gas for the project.

But if you did fill up the pipe and needed expansion, the first two ways you could do it is the pipeline could see it in its interest to expand or if there's the FERC new powers.

The third way is 8.7, under the contract. And what you do there is it's a right given to the State to initiate within the LLC process an expansion, and that was what we negotiated.

The State rights start with the fact that any person, including the State, is unable to secure additional capacity to ship on the mid- -- on the project. That means the GTP. It could be the gas transmission lines. It could be mainline.

I should say in -- these provisions apply in Alaska, because the law in Canada is considerably different. The law in Canada is that the NEB does have authority to order expansion, and we, therefore, thought that what we most needed to do is deal with the Alaska situation, given we had the rights under law in Canada.

There are a number of steps, but

upon receipt of the expansion notice, the project shall diligently prepare a FERC application. And there are requirements about the size of the expansion. There are minimum size and also maximum limits.

The idea is that expansion is -- is related to sort of the engineering of the pipeline. There are costs associated with it. There can be inefficient expansions and efficient expansions. When you get into inefficient expansions, you have the potential for fights about who should bear the cost of the inefficiency. And so we put a -- we agreed to, rather, minimum size. It's different for the mainline as compared to the gas transmission lines because of their different size.

And it doesn't apply to a major looping of the pipeline, one in excess of 100 miles.

And then we picked up the language, most of the language from the federal statute on expansion as to the issues that should be balanced in expansion proposal.

There's also requirement that the expansion shipper be creditworthy. Obviously, you want someone who can pay for what's going on, pay in advance the costs of preparing an application, and that they participate in the expansion open season. Yesterday, there was a question about frustration of the open season. I checked that overnight. There is a requirement that the party complaining, the expansive shipper not having capacity, not only start the process, but also participate in the expansion open season.

Again, to repeat a point, by participating in the open season, the expansion shipper is not guaranteed any preferential rights. If -- once the process is kicked off at FERC and the expansion shipper participates, there may be other people who come out and say, We want capacity, too.

And when that happens, you go through the normal open season process of allocating capacity.

If -- two points. If we feel that the LLC is not moving along quickly enough on the State-initiated expansion, we can go through a dispute process, the dispute resolution process of the contract, and it's a faster process because we skip over the first step of having an informal, amicable meeting trying to work out the problems. And we, essentially, go for an injunction under the dispute resolution processing.

Go to it and comply with your obligations under the contract. We do not have the right to damages in this case. But we do have the right to an injunction which is really consistent with what we want. We don't want damages; we want the pipeline to be expanded.

Then there was a provision at the end of the expansion section that says: If the FERC comes out with an expansion order that is in a major way different from what was proposed, the entity, the project entity, let's say, at the mainline -- it could be a gas transmission line, too -- could vote -- will reject the certificate unless the differences are minor.

And, again, this was a negotiated position. There were special rights given to the State, and the argument was made that this is a particular expansion that everyone hopes never will occur because they hope there is cooperation in expansion, and that the balance of what is worked out is so carefully done under the contract that if the FERC disturbs the balance of this particular provision, the companies don't want to be forced to accept it. That's what's behind that.

They can accept it, but they don't want to be forced to accept it.

I should say there's a lot of language in the State-initiated expansion section about the considerations, and it does not foreclose rolled-in pricing, it doesn't require it, it just copies what is in the federal statute that costs are covered, whether on an incremental or rolled-in basis by the rates that are set for the expansion.

I'm going to go on to impurities which is a sort of interesting contract article because it goes beyond really the pipeline project and involves the working interests owner at Prudhoe Bay, the field interest.

We wanted -- the issue is not really the treating of the gas. Treating means the gas comes out of the ground with impurities like CO2 water, hydrogen sulphite, and there's a lot of CO2 in Prudhoe Bay, at least, Prudhoe Bay gas, and that has to be taken out to make the gas acceptable to the pipeline.

The question is how those impurities are disposed or where they're disposed. The FERC will certainly regulate the treatment plant in access, in rates. But it doesn't usually require a provision and probably could not require that the working interest owner accept the impurities. So the treatment plant can be spewing out or processing out the impurities, but they've got to go somewhere. They usually have to go into the ground. And where they have to go in could be the Prudhoe Bay field or possibly it could be somewhere else.

And so what we were trying to deal with here is an arrangement where the State and others were not caught short or subject to unfair terms on disposal services. And so there's sort of a tennis match, again, between the treatment plant and the working interest owners as to who will accept the impurities and on what basis.

So, as you work through the language, you'll see that we've required the producers as working interest owners -- and they're not all the working interest owners in

Prudhoe Bay, but there are a lot of -- a lot of them percentagewise -- to analyze properties where -- whether they could take those impurities into the Prudhoe Bay reservoir and the terms on which they're offered -- you see, and I would correct this slide, but it reflects the statutory language: If the GTP is not regulated by FERC. Well, the GTP will be regulated by FERC, but the question is: Would the FERC regulation extend to disposal services, which is not -- is sort of a subissue within there. Of course, if it is regulated by FERC, whatever FERC does, controls.

But the more interesting provisions of this clause are when you get down to the disposal services, and you have the working interest owners analyzing the reservoir as a disposal site and the terms of access to that site. And -- and, again, the working interest owners can only be the ones -- you could only bind, as part of this contract, the ones that are connected with the parties to the contract. But we have bound them. If the working interest owners of a property agree to return and dispose of the impurities from a treatment plant, each participant that is a working interest owner in that disposal property must vote to allow the State to return and dispose of impurities removed from the State gas delivered at the same rate, nondiscriminatory, equal treatment, as other owners.

So the point there was we were worried that we would be -- as owners of gas, have liability for the impurities and have nowhere to go with the impurities. And they would be probably a hazardous substance or will be under environmental law. So, it was a lot of push from the State to get the right to have a place to dispose of the impurities and on the same term as others.

Now, also, the third-party service clause, which, again, is sort of interesting because of the stretch under the contract. Each producer, meaning each party to the contract, who enters into an agreement to dispose of those impurities in another property must allow the State to do so and on the same terms as it gets itself.

That is sort of a -- a clause that is very protective of the State interest and is designed to insure fair treatment, equal access.

And it took -- it took a lot of long nights to get that one, too.

Let's go to Article 9.

Article 9 addresses, as it says, in-state markets. You recall that the Federal statute talks about in sort of -- sort of strange language that by the time a certificate application is filed and granted, the certificateholder must have studied in-state needs. So it's sort of -- when you think about how it's constructed, it's a little strange. But we've moved that up.

It was moved up first in our comments in the open season rule-making, and then FERC filed it, which is prior to the open season there has to be a study done or adopted by the mainline entity of in-state consumption needs and off-take points. And, obviously, there's a value to the State in getting that study done as soon as you can, and certainly before the open season, because doing it before the open season allows in-state would-be shippers and lateral proponents to have the information and be in a position to bid in the open season.

There's an economic reality here,

too, which is in-state needs are not stable. They change over time, and so you have to have some knowledge and do the best you can with it at the time of the open season, but certainly there would be no advantage to the State to having the study deferred to after the open season.

The contract also requires the mainline entity to identify, after consultation -- with the State, four offtake points in-state. This was one of the Governor's six principles, and also require that the mainline entity fund the four offtake points in state. So that's the valve, the flange where the gas would go off to in-state uses.

And also conduct a study of NGL processing opportunities in Alaska. There have been a number of those studies going back to the Dalshal (phonetic) study more than 20 years ago, but we wanted it studied again, and the mainline entity has to do it.

I want to skip down to the third quirky dot. When it says: The contract does not require any party to fund in-state distribution facilities, those are the facilities on the other side of the flange off the interstate pipeline.

And that, as I've said, is outside the project, it's for anyone to build. But we have required the mainline entity to cooperate in the design and engineering of those facilities with the party who wants to take gas off. Because you don't want the mainline bulking. It's better that the mainline designs -- makes whatever design accommodations or changes that are necessary for that offtake before the final design of the project. So there's a cooperation clause.

Skipping up to the top of the page, we've talked a little bit about segmented capacity. But the idea is that you could in-state take -- I would emphasize the in-state, that you could -- if you've got a contract to a point here over here, that you want to take it off before then, you could segment the capacity. And that what it means, the service in-state offtake points that are upstream of the firm contracted service point because when you contract for service, you'll contract to a particular point.

Later on, 9.4 provides that you can make new arrangements for -- once you've made a set of arrangements, you can change or make new arrangements for delivery in Alaska as long as that doesn't cause un- -- any sort of unpaid-for stranding of capacity. So if you signed the contract to go 300 miles and you only want to go 100 miles, you're going to have to pay for those extra 200 miles if you -- if that's a changed or new arrangement.

Recall what I said yesterday, if you start out, however, knowing you want to go 100 miles and not 300 miles and you contract for that service, that service is supposed to reflect the costs of going the 100 miles and not out of Alaska.

Anyway, 9.4 is designed to deal with changes later, and what will happen in those circumstances is that if there is a change and there's some downstream costs that are stranded, as the word goes, by that change, usually the shipper makes a deal with its new -- it depends where the point of sale is actually, but with the purchaser to pick up those costs and they're passed through in that way, but that would be a point of negotiation.

With that, I'm leading up to what

the fiscal terms of the contract are, and this will take a lot of careful discussion.

Dan's presentation has the advantage of having color slides, so it's in Technicolor.

COMMISSIONER CORBUS: It might be appropriate to answer these questions.

MR. LOEFFLER: I've been given a handful of questions here and will -- I will not give you the fiscal stability covenant yet.

The State -- under Roman -- at Romanette ii, the State will be responsible for the reimbursing -- for reimbursing the participant for that loss. Why does the State reimburse 100 percent when we are only 20 percent owner of the pipeline? Are there other examples of this method being used in this manner?

On the first point, the theory of the reimbursement or indemnification, if it happens, was the RCA is a creature of the State. It's a creature of State law and the State, in some political sense, is responsible for the RCA, and therefore, should be on the hook if this set of circumstances occurs.

Are there other examples of this

method being used in this manner?

There are a number, and we'll get into them in the fiscal section of potential indemnifications under the contract. Being used in this manner, I would say no, but there are indemnifications, and we should get into those.

The limitation on loss is a universal term in the contract, as I -- as I referenced in the -- I think it's the liability section of the contract.

If the RCA sunset is not extended, who will have jurisdiction?

I'm a little unclear here. Let me try and speak to that, but I -- I would ask clarification of the question.

I don't see that there's an RCA sunset in the contract.

Jurisdiction of the FERC is based on the U.S. Constitution, the Interstate Commerce Clause of the Constitution, and there's a number of Supreme Court cases that say if the area is constitutionally reserved for regulation by the Federal Government, then the states cannot have jurisdiction, and the Federal Government can choose the form of regulation that it wants, whether it's extensive or even deregulation.

It may be the RCA sunset clause is a question of State law that I'm missing, so I will consult at the break.

If the NEB uses a different tariff methodology, how does the FERC or the contract under 8.7 deal with it?

More questions.

The FERC can't control the Canadian government. The FERC has jurisdiction in the U.S. parts of the project. NEB does it in Canadian parts of the project. And each government has its sovereign powers on setting the tariff within the part of the project that's subject to its jurisdiction. I -- I don't see that we can do anything. But, certainly, the NEB can't set the FERC tariff and the FERC can't set the NEB tariff.

If expansion cannot negatively affect current shippers, how do we reconcile that with the fact that FERC Rule 2005 puts a presumption of rolled-in tariffs?

There are various scenarios where an expansion could lower the costs for all shippers because you might have more volume over an increased -- divided by increased costs, but not disproportionately increased costs. So that might lower the tariffs. But I don't see that there's necessarily a conflict anymore than there might be under the presumption which can be rebutted at FERC.

On expansion, why can't -- why can't the State ask for expansion for in-state lateral? This seems an important right to have.

If neither State-initiated expansion or ANGPA mandatory expansion can impact rates, doesn't that result in incremental pricing?

Not necessarily on the second, for the reason I gave. It depends on the costs of the expansion. It's generally thought that in-fill compression, as opposed to looping, can result in a lowering of average costs for the total system. The odd thing about the debate over incremental pricing and rolled-in pricing is that by promoting and -- successfully promoting rolled-in pricing, the State gave up the argument and independent shippers gave up the argument that incremental pricing would be a benefit to them. Because if the cost of the expansion had a lower average cost priced incrementally, a lower cost, they could have a more favorable rate than they would when they roll in the rate with the total pot of costs on the pipeline. But it was thought, generally, that rolled-in was a better way to go because it also covered the opposite situation where expansion was by looping and added to the average cost of the system.

So it depends a lot on how expansion occurs.

So it doesn't necessarily result in incremental pricing.

Why can't the State ask for expansion for an in-state lateral? This seems important -- an important right to have.

Well, the State can ask for it. It can ask for it within the LLC regardless of the rights. And we thought we had a couple ways to go at it if we need to. We were concerned, listening to complaints that we had from independents, that the expansion need was for the new explorer who couldn't get on the mainline and wanted to take its gas out of state. And so 8.7 was aimed at that problem. We didn't see a parallel problem with respect to an in-state lateral.

Does the provision that the project entity must -- must -- I can't read the word -- must something a FERC order on expansion if it differs from the provision -- must reject a FERC order on the expansion if it differs from the provision of the Stranded Gas Development Act -- that's not "or differ from." If it differs from the provision of the Stranded Gas Development Act -- "contract" is the word that's missing, meaning that the FERC mandatory expansion is superseded by the Section 8.7 right.

No. They're independent. 8.7 is a contract right. It does not modify and can't modify the rights under the statute.

Can you explain why it is in the State's best interest to take royalty gas in kind rather than value? How much of the State will benefit?

I think Pedro has -- and others have talked about that. It was a very high-level decision made initially in the contract negotiations that the State wanted to take its gas and have the opportunity as well as the risk to market its gas, and there is opportunity as well as risk.

I would point to some of the programs that have been undertaken by the Minerals Management Service of the Department of Interior in the state of Wyoming, where they have found that they have increased the return to those respective governments -- there's public reports on this -- by taking the gas in kind and doing the marketing.

Another thing it does, and some people think this is a benefit -- I do -- is that if the State takes its gas in kind, it eliminates potentially a lot of litigation over what is the right value for the sales or the measurement of the value of the sales that are made by others.

If you're in a value situation, you're in a derivative position. You have to examine the sales, a lot of sales made in different places at different times. You will spend a lot of money on litigation on what is the right value. Some people see a value to that litigation. But you will avoid all those sorts of disputes by taking your gas in value, but you will also have the responsibility, the opportunity, and the risk that goes with taking the gas in kind.

How much of the State will benefit? It will be a choice of the State Administration at the time to sell gas in-state as well as out of state, and there will be public policy issue about what's the best use of the State resources in selling its gas, should some be reserved for in-state use, can it be lawfully sold at a lower price than the State could obtain in the interstate market and things like that.

What are the plans for in-state processing, marketing, sales for our gas taken in kind? Are the associated costs included in your $20 billion estimate?

On the second question, the costs that have been floated are the costs of the project, they're not in the costs of marketing. I believe the fiscal interest finding has some discussion of a range of marketing costs on a volumetric basis, not on a total-cost basis.

What are the plans for in-state processing, marketing sales? This is beyond my jurisdiction.

The Department of Natural Resources has spoken to that. The fiscal interest finding speaks to that. And I will pass me on that.

Why did the State agree to the provision of Article 9.4? No party is required to sell gas to any Alaskan purchaser. Wouldn't a provision that requires sales under certain conditions better protect Alaskans in the long run?

I don't think -- I think it would have taken a very long time, and I don't know if we would have achieved it, to figure out a legally enforceable clause that would require sales under certain conditions. The devil was, again, in the details about sales under certain conditions. You know, at a very high level, maybe there would have been a value. That clause has other language in it about parties are free to sell or the State is free to sell. There's a huge amount of gas available, and I think it was not in the companies' free-market ideas to say that no party is required to sell, but no party is prohibited either. It -- it really doesn't mean much.

Expansions, page 45, State's right to seek specific performance is in its -- is its exclusive remedy for any breach of Article 8.7.

What exactly does that mean?

I touched on this earlier. It means that the State cannot get damages, but can get an injunction to force the contract to be carried out with regard to an expansion.

Impurities and working interest owner. Each participant -- quote: Each participant that is a working interest owner in that disposal property must vote to allow the State to return and dispose of impurities. If it is a vote, doesn't this imply that they could vote no? Because it says: must vote to allow.

So, that's that question.

You have referenced -- no. You have referred to the producer appeal of the FERC order on design changes to make the pipe bigger or expandable. Doesn't Section 8.7, on page 86, give the producers the right to resist an expansion certificate if FERC grants a certificate on a basis different than the original design? This would seem to allow the producers to win their FERC challenge outside of the court system. We should do all we can to maintain the benefits we want at FERC and not negotiate that away.

There's no question there.

Anyway, 8.7 does not supplement mandatory expansion, does not affect other voluntary expansions as to which the rolled-in pricing presumption applies. It's an additional right on top.

Why does the contract not require that all expansions be done on a rolled-in pricing mechanism?

You've got FERC law. We didn't accept, when we created a new right -- could not and did not intend and did not disturb the FERC law on that.

Under State-initiated expansion, explain why one condition to the sponsors going forward to expand is that expansion not required in any of the producers to pay a higher right than they would have without expansion. Isn't this a more restrictive than the no-subsidy language we won at FERC?

I see a sort of similarity in these questions, even in the handwriting.

The -- the issue on any expansion, any of the three expansions, is: Do you disturb the rights of people who signed up for capacity on the basis of a particular rate well after they signed up but before their rights have expired? And the idea, both in the Congress-accepted and State-initiated expansion, is that you should not add costs to the original shippers and -- and disturb the contracts they made.

Isn't that a more restrictive than the no-subsidy language we won at FERC?

Not necessarily. You've got to -- if I recall the dialogue I had with the chairman of FERC in December, 2004, he didn't know what a subsidy was, and we had a little exchange on that. And subsidy covers or no subsidy covers a lot of territory. And FERC ducked the question on re-hearing in Order 2005A, what a subsidy was. They said they'll deal with it when they come to the time.

If a subsidy helps you, it's obviously a public-interest benefit. If it hurts you, it's a subsidy. And so it depends which side of the issue you're on.

What if RCA asserts jurisdiction over some upstream asset, and it was a rate established that is lower than the contract rate commercial agreement, would the State have to reimburse the difference?

I don't think the RCA could successfully do that. If in fact, the area is reserved for federal jurisdiction and the federal government has decided not to regulate in that area, would it have to -- it gets to a very complex factually -- question -- although the State might have to reimburse some part of that difference, it goes: What would the difference be? The difference could be, for example, a lower rate of return. In that case, the limitation on liability knocks out reimbursement, because that's lost profits. So that's as much clarity as I can add to that.

The contract establishes the diligent standard for arbitration. Wouldn't a prudent operator standard be more conventional and generally better understood legally?

Having looked at some of the case law -- and prudent operator, it covers a lot of sins -- no, I don't think it would be any easier to apply.

Bill, any more?

COMMISSIONER CORBUS: Yes, we do. We have a total of ten questions more. And I would suggest we take ten and then come back, and we're going to answer eight of the questions. And two of them, one to do with force majeure and the other one for the period of fiscal certainty, we will consider later on in the day as we address these issues.

So let's take ten minutes.

[Break]

COMMISSIONER CORBUS: We are ready to resume now.

Mr. Loeffler will answer the eight questions he has -- we have before us, and then we are going to turn it over to Dan Dickinson who is going to cover parts of Article 11 and -- and thereon through Article 14.

MR. LOEFFLER: Let me continue. I want to go back on the RCA sunset question. And the question was: If the RCA sunset is not extended, who will have jurisdiction?

Well, the answer is whoever the State Legislature creates to follow on the shoes of the RCA as it created an entity to follow on the shoes of the APUC.

FERC is given -- both FERC and RCA are given their jurisdiction by legislative bodies, and FERC doesn't jump into the jurisdiction of the RCA because the Alaska Legislature changes that jurisdiction.

Next is rate loss. The RCA 2002 decision has said that TAPS owners exceeded just and reasonable rates by 50 percent -- 57 percent between '97 and 2000. If the RCA decided that rates should be lowered, would that be considered a loss and require state reimbursement on either past overcharge or future rate increase -- decrease?

No. Two points, it goes back to the jurisdiction on oil pipelines versus gas pipelines. The RCA Order 157 on oil pipelines legally could only decide that the intrastate rates on TAPS were too high by that margin. And even there, there's an issue of whether they could do that because of the impact on interstate rates, which is now being litigated at the FERC.

But the difference is that on oil pipelines, the RCA does have jurisdiction to establish the intrastate rate mainline. And on gas pipelines, it does not.

So, if the RCA -- I don't know why it would do this -- but tried to establish a rate for the mainline on the gasline, it would be acting beyond its jurisdiction. It would not be a loss that the State would reimburse. It wouldn't even be a loss.

The contract defines an affiliate as being 50 percent or more owner. Doesn't the FERC rule define affiliate as 10 percent or more owner? Why the higher threshold?

The rules are -- serve -- in the contract serve different purposes. I believe affiliates are used for things like affiliate transactions, enforcement of the various requirements on no favoring of affiliates. Affiliate in the contract is used for a different purpose. It doesn't disturb the FERC 10 percent.

Has the Administration discussed with the RCA the exclusion of RCA oversight in the proposed contract?

I, frankly, am not privy to every discussion the Administration has had with the RCA. I believe there have been some, but I don't have complete knowledge there.

Is there any requirement in the contract that the mainline will make maximum use of the federal loan guarantee in order to keep tariffs low? If not, why?

It's really if not, why not?

In the LLC that is nearing completion in negotiation, there is a financing article which currently addresses the loan guarantee. It was handled -- or is being handled in the LLC and -- and that will speak to however it comes out.

One point about the federal loan guarantee is that -- this question is a bit like: Is there any requirement that you will do business with the Bank of America?

You don't know what the terms and conditions will be on a federal loan guarantee. And until you know what those terms and conditions are, you don't know whether the cost of the loan is acceptable.

So, a requirement that they make maximum use of it would obligate you to sort of an unequal bargain, because you don't know what the Feds will want. But there will be language about use of the federal loan guarantee, I anticipate, in the LLC.

This one I'm going to duck to -- but I'll state the question: Excess state capacity in management. At what point would the risks become unmanageable?

That's a -- not a lawyers' question, that's a question for the policy people of the state, and I guess we'll refer that to Mike Menge.

If in-state rates are mileage sensitive and does not -- and does not subtract the main pipeline tariff, does this just mean the wellhead price remains the same and the producer profit increases or is the cost of gas less at closer mileage points?

I think what's going on in this question is the question of how gas will be priced, and that goes to both State gas and producer gas.

So I think what's behind the question is: What would be the price of gas to an in-state user? A seller of gas might have a lower cost of transportation to ship to an in-state point. And the question is, on a sort of net back calculation: Would a seller of gas look at what it might receive at the Alberta hub and realize that it would not have to pay the cost of transportation all the way to the Alberta hub, and would the seller of that gas, therefore, give a break in -- depending on how you want to look at it -- to the in-state user because of the savings in transportation costs, or it would say, I want the price at the Alberta hub minus the cost of transportation; therefore, I'd make more money selling in Alaska.

That's a question that each seller of gas will face. The normal way a market works, if it's a free market, is there'll be a -- you will choose the opportunities that give you the most profit. It will get to a different question for a State seller of gas, which will have to decide whether the savings in transportation costs by selling gas somewhere in Alaska should be reflected in a lower price or not and whether the State can lawfully make that sort of sale under the clause of the Alaska Constitution that calls for maximum return to the citizens of Alaska.

But, again, that's really a -- you can't answer that, because you don't know what any seller of gas will do.

How nearly linear do you expect the mileage rates to be for a 500-mile rate, on a

2000-mile pipeline, be 25 percent?

I can't -- I can't give you a good answer on that, because I don't know where the costs will be accrued on the Alaska portion of the pipeline. And we wanted some flexibility to argue about what the right cost allocation is, so that's why we use mileage-sensitive. I know historically we fought very hard for an mcf mile basis which would be quite a linear basis, and I guess when the issue comes up again, the State will have to decide what it wants, but we have flexibility under the mileage-sensitive clause to argue for what we want.

There we go.

We're going on to a new topic, really, the fiscal stability covenant. And, really, here we're getting into some very core obligations of the contract with substantial financial consequences for the State. But, remember, the idea of a Stranded Gas Act contract is that the State is doing something that is pretty unusual in the United States. If approved, the contract would provide fiscal stability to the sponsors of the project for a very long time to give them certainty about their costs and the rules of the game won't change after they make their investment.

And so it took a lot of work to work out what is the fiscal stability covenant and the implementation of that covenant in the contract. And so I'm going to give you a little information on 11.1 and touch 11.2. And then Dan's going to go into how it actually operates and part of the rationale there.

The covenant summarized in a sentence is just what I said, the contract obligates the State to provide physical certainty for each participant's interest on its oil and gas business activity in Alaska for the term of the contract. They're differing terms, as we learned yesterday, 35 years from the startup of operations for gas. That's the maximum time allowed under the Stranded Gas Development Act. And 30 years from the effective date for oil, and that could be two-thirds of the period for gas.

The -- the ability of the State -- the constitutional ability of the State to provide a guarantee that long and in the way we're providing it, one might surmise, would be tested or will be tested in the courts. The attorney general gave you his opinion and explained it earlier this week, and it's -- it's an interesting issue for a lawyer.

It is clear that states do give tax benefits that last a long time to -- for industrial projects, and this is sort of a nature like that. And we'll see how the courts come out on it.

The Attorney General, I think, was confident that we have a strong position, and I share that view.

On page 52, at the bottom half of 52, the producers for their part wanted to say, sort of a truism, but that in making the royalty payments under the contract, they satisfy their entire royalty obligation, and then by making the tax payments, some are cash payments and some are payments in gas, which, again, is a novel concept, you satisfy your tax obligations except -- and we'll get into these definitions of certain kind of taxes.

When we came to negotiating the clause -- the fiscal stability clause, we wanted it to be a two-way street. We wanted the State to be providing fiscal certainty in the negotiated dimensions, but we also wanted to say that the State was getting something in return. And there's a list in 11.1(b), Romanette i through ix of work commitments and monetary payments and capacity management rights and expansion rights and State ownership, but there are about nine or ten things there. And that is, in a way, the consideration for the contract.

The State is providing fiscal certainty, but in return the State is getting X, Y, and Z.

With that I will happily turn it over to Dan, and he will go into the details and principles in the fiscal articles.

MR. DICKINSON: Good morning. My name is Dan Dickinson. And I'd just like to take a moment to share with you the last time I was actually working in this hall was in the summer of 1984 when I was the master carpenter for the Alaska Repertory Theater. We came down here, and at the other end of the hall down there, which is on the other side of the sound divide, we were -- we had to build a false proscenium for the touring production of "Fools." I know it's great fun to wander down there now. I guess Gallagher is going to be here this weekend. And for those of you who don't have teenagers, he does all kinds of strange things with fruit and vegetables that fly all over the place. And there -- down there, where we were hanging all these black shmates to create a sort of a theater, they're now hanging large pieces of black plastic. So, anyway, just an interesting -- if you want to see what the -- how that preparation goes, it's happening beyond the sound wall over there.

What I'm going to talk to you today about is the Section D of the contract which are the fiscal articles, basically, Articles 11 through 25 with a couple of appendices thrown in. I think what I'm going to try to do to get up to the next break is probably talk about Articles 11 -- the rest of 11, 12, 13, and 14.

What I'd like to do is start out with -- before I sort of get down into the broccoli in the actual articles, I want to talk about a couple of principles, that, even though you won't find all of these exactly in the -- in the contract, I think they are -- they are critical because there's lots and lots of details in the -- in the contract, and sometimes what's -- it's better to go up to 50,000 feet and look at what we were trying to do.

The first principle that was here is that the distribution between the State and the political subdivision remains a legislative function. And what I mean by that is you'll find lots of places in here where it says, here's a -- you know, there's an obligation. The contract is between the State and the producers. There's an obligation, but instead -- instead of making a payment to the State they're going to make a statement to a political subdivision. Every time you see that language, you will see that that -- the amount that the political subdivision gets, the formula for it will include their mil rate over 20 mils, and the one thing -- I mean, the Legislature maintains the right -- you know, to pass the legislation that says how you can -- what your mil rate can be, what conditions it can -- it can go to certain places. Currently there's a cap of 30 mils. Various legislation over the last five or six years have -- hasn't passed but has looked at changing that.

The point is whenever we talk in this contract about a distribution between a

State -- how much goes to the State and how much goes to the political subdivision, this contract does not freeze it. That is not being frozen for 30 years. What's being frozen is a formula in which the mil rate is a piece. So I think that's very important. Because I'll probably use as a shorthand say the munis are going to get this, or on Saturday when we talk, about the munis are going to get this piece of it. All these taxes that are being replaced, and so they are payments being made, instead of a tax, it has a municipal piece. Like I say, what is critical is you always have that ratio, that political subdivision ratio in there.

The second general principle is that direct taxes on the project are being replaced by PILTs, so I'm going to use a couple things as shorthand here, PILT, I think payment in lieu of tax. Basically it's a contractural payment which in many respects is simply replacing a tax that's currently being levied. In general, where it was a direct effect on the project, we have simply said there will be no taxes levied during the construction, say, and what we're replacing it with is a throughput.

We're replacing a direct tax being levied on the project with a PILT, which is in the contract.

The second two -- the third and fourth principles really deal with that whole other world of taxes which could incidentally fall on the project or might affect it but aren't really directed at it or directed at a major element of it.

And there really are sort of two ways of looking at -- at the taxes here. The first one is: If there's a political subdivision tax, if there's something being levied by -- by, you know, a nonstate entity, but, in general, and we'll get into the specifics, but in general, the sponsors pay that and then they either come and they get reimbursed by the State or in some cases they don't, but the mechanism here is that -- that the relationship between the municipality and the -- and the -- and the sponsor group a participant here is not being altered by this contract.

The flip side of that is that sponsors are generally exempt from state taxes. And so if the State goes and -- and, you know passes a tax which has an effect -- again, we'll get into the specifics, but the general notion is that the sponsor simply doesn't have to pay it. If they're paying their PILTs, as Bob said, if they're paying the obligations they agree to under this contract, they simply don't have to pay additional obligations that the State -- the State might levy on them. Flip side on the political subdivision, they do have to pay them, but then through a mechanism the State will make them whole.

So I think these are four principles that it's sometimes -- it's certainly useful for me sometimes to get back to and remember. That's why we did this, that's why sometimes we get -- when you have 7 or 8 different things we're looking at, it really was trying to implement these simple principles.

What I'd like to do is give you a couple of slides. I'm going to step maybe more into the -- well, these are slides I took from other places. But just to give a context of some of the taxes we're talking about, to look at the overall numbers. And this is simply out of the fiscal interest finding. It's Table 8 and it divides up the gas -- the revenues the State's going to get from the gas line, from -- between 2007 and 2050. And really the two points I wanted the slide to bring home to folks are that three-quarters, I think I actually calculated out 72 percent, but by far most of the dollars that are coming to the State as a consequence of this project are going to be coming through gas sales. As we go through this later, you'll see, you know, we're taking our royalties in kind. They will be -- you know, we will be getting -- monetizing those by selling them, the same thing, the production tax is being replaced by a slug of gas and then -- and then we'll take that royalty tax and that tax gas, that will become the State gas. We'll be selling that, and that will form the vast majority of the revenues. The smaller pieces are income tax, additional tariffs that we'll get because our ownership share in the pipeline will be slightly higher than the amount of gas, the upstream and midstream PILT, which are really replacements for property taxes and -- and other elements. But the main point I want to get, and this slide will keep reappearing as I sort of go through each piece, to emphasize is that on a lot of the PILTs, very important, billions of dollars involved, but really, the focus here is, you know, go back to the Governor's six points here, we are taking a piece of project and most of the monetization that's occurring is going to occur as a consequence of that. As folks know, there are certain risks attendant to that, but that's -- in this, as we go forward, really what I'm talking about today mostly are going to be the remaining one-quarter, the other wedges.

This compares to where we were where we are now, where we were, I guess it's almost a year now, the fiscal year that ended about 11 months ago. Interestingly, sort of almost coincidentally, if you look at the two largest pieces, these are unrestricted now, so we don't have Permanent Fund -- money going to the Permanent Fund, but the two largest pieces are the sort of the bluish on the left and the -- and the yellowish piece on the right are production taxes and royalties. And so right now we're also at a point where the things that are being replaced by the gas now constitute about, again, 75 percent of the State's total unrestricted revenues. And the other pieces that you see there are -- and incidentally, by the way, it's about the same ratio, about -- of that piece, the royalties are about twice the size of the production tax piece. And if you -- if you look at the gas, you'll see the same thing. The tax gas will be about -- about half the size of the -- of the royalty gas.

But, you know, you have the two largest pieces are those and then the remaining pieces are property taxes, income taxes, and then the sort of the dark or the burgundy wedge near the top there, the next to smallest wedge, which is nonoil and gas revenues, which are about $300 million in our current unrestricted revenue piece.

And the final piece, the final slide -- the final color slide here, just again to put things in perspective are local tax revenues, roughly a billion dollars in 2006. I guess that's -- you know, I'm going to believe that's probably 2005, but I'll double-check. Yes, it is. It's from the Alaska taxable 2005. By far the largest piece are property taxes, that's the yellow section on the bottom. And then the three other wedges are general sales taxes, the special oil and gas property taxes, and then the -- kind of the red wedge off to the side there which are what are called special taxes, about $52 million worth of special taxes, and probably that's a good -- special taxes is probably a good lead-in to move in to what -- how -- how the fiscal contract is structured.

As I enunciated four simple principles, what ends up happening is taxes end up falling into one of, yes, eight categories. It's not quite as complex as it looks, because really two of them are just subcategories, so there's only six. But fundamentally things fall into eight categories. When we present on Saturday, we'll sort of present a little more with boxes and kind of show which ones go where and how they get broken up. I'm going to go through these all, but let me just go through these quickly. You have capped taxes, targeted taxes, fixed payable taxes, vessel taxes. This one came in late at night. You can tell we were being creative, something we call other taxes, restricted taxes -- by that time we were running out of short terms -- reimbursable property taxes, and then nonparticipant reimbursable taxes. So these are eight categories and each of them is dealt differently under the contract.

Let me go through, and these are all -- what you will find, what I'm going through now, are things you will find in the definition section as opposed to actually in Article 11.

What restricted taxes are is simply taking a set of statutory prohibitions that are found in law now and saying those -- you know, as they were read and applied on October 1st, 2005, and that's a date you'll see a lot. There's no magic about it. That sort of -- at one point that was something that got pinned down, and whenever we were taking a date to pin something down, we just went back to October 1st, so it wasn't -- we didn't have ten different pin-down dates, if you will.

But, fundamentally, it goes through four provisions and says these are going to be restricted taxes. And what I really -- how I would really characterize those is they are natural resource taxes. They are taxes on the gas, on the oil, in the ground, on the production of it. Fundamentally, the way these came about was when the oil and gas taxes that we have now were passed, provisions were inserted that says, this will be in place of, and then there is that list. I'm not going to go through and read these. There are actually some overlap and there are some different statements, but the main point I want to make is they all exist in statute now. 43.29(8)(10) was added as a consequence of the Stranded Gas Act. So it's only been in place for, what is that, seven years. The other ones go back to the '70s.

Capped taxes. Capped taxes are really going to be that set of taxes which are general purpose, but who might have some effect on the project. Sales or use tax on the sale of goods or services. I know folks in Juneau here are very familiar with sales taxes. You know, as a slight digression, our Department back when I was with the Department of Revenue, we got involved in the -- what's called the streamline sales tax project, which they're trying to further the ability to -- for commerce between the states. They're trying to streamline the sales tax applications. And people sort of look at Alaska and are sort of stunned. We have 107 municipalities, each with their own different sales tax and sales tax rules by ordinance. Sales taxes are widely used in the state. The fact that some of the larger cities don't have them, but they are widely used in the state.

We have gravel severance or mining license taxes in there. You might not think that has a lot to do with this project, but as folks think about some of the things that can happen, some of the work that has to be done, they got focused on perhaps there being taxes on their ability to move gravel or create pads or those kinds of things.

Finally, the last category is the excise tax, including the major excise taxes we have today, which are motor fuel tax and bed tax. Actually I should -- there are also sin taxes which we didn't deal with here. We can't imagine the projects worth having direct use of cigarettes or liquor. And all of these exclude restricted. What does it mean to be a capped tax? Again, we'll get into it later, but in the definitions you'll find out that there is a $20 million annual cap on total collections under each of these individual tax types.

Before -- another acronym you'll see a lot, CoCO, which is commencement of commercial operations. That's going to be when gas first starts to flow. Before the commencement of commercial operations, you have five entities, basically the three sponsors we're dealing with here, plus the mainline entity, plus sort of all other entities together. The entities will be building upstream pipelines or building the GTP, and they're each capped at 4 million, so four times five is 20 million. After the commencement of commercial operations, when there won't be a lot of construction going on, hopefully won't, and there will be lots of expansions but there won't be the same scale of construction. We have four entities, the three entities we have plus all other entities, and at $5 million apiece.

So those are going -- those are the capped taxes and they are, like I say, the -- the general use taxes.

We next go to targeted taxes, which I'm calling the capped tax gone bad. What that means is, what happens if you start out -- someone says, well, gee, this is a general use tax, but as it turns out, it isn't a general use tax, because the project or a combined set of entities, the project or their affiliates end up paying most of the tax. So, what a targeted tax is is defined as -- there's two criteria. The first one, and this is very important, is that it has to be enacted or changed after this date again, October 1st, 2005. In other words, current taxes are grandfathered in. They can never become a -- a -- a targeted tax. So, if they there's some entity that now has a motor -- say a car rental tax, and -- and in that same space the producers decide to build -- that's going to be where their central yard for keeping vehicles are. For some reason that -- that tax ends up collecting 30 or 40 percent from that central yard. If it was place in before, it wasn't put in place to exploit that fact but it was already there, in fact, it can never become a targeted tax, even if it meets the second half of the definition. So current taxes are grandfathered in. Obviously we had this enacted or changed, because you can't sort of use -- you couldn't take an ordinance and sort of morph it out of shape and say, well, the ordinance was already there in place.

But the second half is, if you have a capped tax -- and what we find is that the payments -- the participants, the affiliates, contractors or subcontractors in any calendar year exceeds 20 percent, then that is viewed as a targeted tax, and ultimately the State will be -- if those are municipal taxes, the State will be either reimbursing them or else the entities don't have to pay them.

So, capped taxes, in general, you have two restrictions on them. The first one is the cap itself, and the second one is if that tax in fact turns out not be to general, but is targeted, then -- then it becomes a targeted tax. If it is targeted, it then becomes by definition a targeted tax.

The next category are fixed payable taxes, and in some sense as people talked about freezing taxes -- and this is sort of one two places where we actually, in a sense, did freeze them. What these are is they are existing property taxes or could be, again, if -- you know -- you know, in all this we're not -- we use the existing law sort of as an example. I think if you look in the contract we tried to frame the words so that if you had something that looked exactly the same but was a different ordinance number or something, that wouldn't take care of it.

And this really deals with five areas of taxation. The first one is nonproject real and personal taxes under 29.45. As folks are aware, 29.45 is the general grant of taxation to localities under which they can put in real or personal property taxes. So basically, if there's an existing -- again, if there's an existing ordinance, that will be -- that -- that is a -- or one -- that that will be -- if it doesn't change, then the sponsor group or members of the sponsor group would still continue to pay it as if nothing changes.

What fixed payable means, is if it goes -- if the tax changes -- so, for example, let's say it were -- it were repealed, then the sponsor group would end up paying that same tax to the State, because we've frozen it as it was. If the tax increases, then the State would reimburse the sponsor group for the difference between what they would have collected and what they did collect. So basically it's frozen in place. It's not a one-way street. It goes either way.

Sorry, I was -- I got off the slide here, I'm not explaining what taxes are, but what they do.

So what's in this category are the nonproject, real and personal, under 29.45. And then moving on to our current special oil and gas property taxes, we have exploration property that is not on the North Slope, production property that is not on the North Slope, and then nonproject or Article 17.2 pipeline property which is just another way of saying if it's not a major gas line, the main entity, or one of the pipelines -- the oil pipelines that we have dealt with in Article 17.2, it will be under this category.

Or it is a vessel tax. I'll talk about vessel taxes in a minute. And, again, excluding restricted. There's nothing that can become -- you know, if a tax morphs into or can be shown that it is a restricted tax, then it doesn't meet this category.

Finally, the final piece here is

reimbursable property taxes. And as I was going through my slides this morning, I realized that I -- for some reason it dropped out. So there is sort of an extra page that was handed around that goes through what are reimbursable property taxes. And, again, it goes through the same kind of analysis. What these are, as I said before, are taxes that are really on the project itself. And they are simply reimbursable. So if a municipality lays one of these taxes on or has a current tax, the sponsor group will pay it, and then the State will simply reimburse it.

So, the first one is, again, project real or personal property under 29.45. If they can show that a tax, you know, actually fell on an asset, a pipeline asset or part of this project, that's reimbursable. As we move down, we have ANS exploration property, that's participant-owned. I think that's very important. Folks are going to be exploring for gas as part of this -- you know, as part of this enterprise, and if they own those assets -- and of course, I think as folks are probably aware, most exploration assets are not owned by the sponsor groups. They, in fact, rent rigs. They rent seismic equipment, drilling equipment. But if it is participant owned, it falls in this category of a reimbursable property tax, excuse me, participant owned and it's on the North Slope.

The next is in transit ANS production property. Again, an example of this would be if modules are being built in Anchorage or Nikiski, while they are there, those entities -- the municipalities can tax them, and properly do, we will reimburse those. When that gets moved up to the North Slope, at that point, it's being replaced by a PILT, and so there's no reimbursement. So we are calling this in transit when it's outside of -- outside of the ANS.

And then, (d) is after the commencement of commercial operations any in transit project pipeline property. Same example. Let's say there's going to be an expansion and the modules for it are being built in Anchorage. Anchorage could tax those. State would -- the State would reimburse those. Once it -- once it was moved out of Anchorage and moved into the borough in which it was actually or the unorganized borough, wherever, when it was going to be moved to a place where it's actually going to become part of the pipeline, at that point, it would no longer be taxable.

So that's the -- that's the last piece of the reimbursable property tax. What I'm going to do now is actually tell you what this all means and how it works through the -- works through the agreement.

Article 11 starts with 11.1, which Bob already chatted about a little bit. The next article is Article 11.2, which talks about the taxes levied and payable to the State. And here again is where we try to bring in one of those principles I mentioned earlier.

The first subcategory are taxes that the sponsor group has to pay and are not subject to reimbursement. And what those will be are the capped taxes up to the cap. So, for example, you know, if the State had a sales tax or if there's motor fuel taxes, which we have now, they're just going to pay those, and until they hit that cap, there's no reimbursement.

The second one would be a fixed payable plus any increment that had to be paid. So they'll pay the fixed payable exactly as it is and then, if, in fact, things change so that there is an increment there, that will be paid. But, going on to B, they are exempt from any payment obligation on the rest -- on any other taxes for the term. And that's basically the establishment that -- or the principle that Bob enunciated.

Moving on to Article 11.3, the first two clauses of that look essentially the same. These are for taxes levied and payable to a political subdivision. And the first article again, is they have to pay and it's not subject to reimbursement, are the taxes up to the cap -- capped taxes up to the cap and any fixed payable tax.

They are exempt from any payment obligation on restricted taxes, which again are sort of natural resource taxes. And the point I would make is, I think if you -- if you look at the -- at the bills now, all this is doing -- excuse me, the statute as it exists now, all we are doing here is taking a current set of prohibitions, most of which have been in place since the '70s, and saying, those will continue under the contract.

There is the other taxes over 10 million. Nobody could figure out what these other taxes were. We thought we pretty much sewed up the docket. But logically there was a -- they were concerned that something would appear out, and it wouldn't -- it wouldn't be closed. So, to close the logical loop, we said, If there's something called "other tax," this is where it will fall.

But this is the third clause, 11.3, which is not found in the section dealing with state taxes, it deals only with political subdivision taxes, and this creates a new category, which is the taxes that they have to pay subject to reimbursement. The State is going to reimburse them on those.

The first one are capped taxes above the cap. So, if there's a sales tax and they end up paying $6 million on it, they can then come to us and say, Our limit was 5. State, you need to reimburse us for that additional million dollars.

A fixed payable increment. So there's a fixed --there's a fixed tax. The municipality decides to change the way it's administered. They raise -- they -- they do some change on it. We have to pay that increment.

The next one is a reimbursable property tax. Again, the -- they will pay the political subdivision. The State will reimburse them.

The next one is our restricted taxes. Same thing. If they -- if the municipality charges that, the State will reimburse. And the other one -- and the next one is the other up to the $10 million. So the first $10 million up to that fiscal stability cap.

The important thing I want to -- the important thing I want to re-emphasize, and it was the first principle on all of these things. All of these you heard me say, well, the state will reimburse. The state will do this. The state will repay, make them whole. The Legislature will maintain control over that.

So if, for example, you found that under this contract we were making huge payments as a consequence of one or two boroughs passing a set of taxes that fit in here. You could deal with that behavior. You could go in and say, okay, we're tired of paying that out. You know, we will prohibit those kinds of taxes. Nothing is being changed by this contract in the grant of authority that the Legislature makes to municipalities to assert and levy taxes. So you will still retain the control over that. What we're basically saying is: Given the world as it exists now, here is how those cash flows are going to go.

Article 11.4 deals with the fixed payable tax increments subject to reimbursement. And I think I skipped ahead of myself a couple of minutes ago and kind of explained how this works. But let me go through it again, make sure I get all the points. Any change in how a tax is administered in the rate or its application, relative to our sort of freeze date of October 1st, '05 creates an increment. An important exception to that is mil rate changes. As folks know, the way municipalities typically work is they come forward with a budget, they figure out what their assessed value is, they divide one by the other, and they say, okay, this is the size of the tax we need to assert. They go up, they go down. As we all know, they tend to go up, more than they go down.

But the point is, those kind of changes are the ordinary business of how a municipality works. Those are not considered triggering a change. What is going to change is if you go and you say, okay, we're going to change the basis of this, we're going to say that, you know, if we said, you know, if interest -- if interest during construction was not deductible on an asset before, we're going to change that rule so that it is, probably would go the other way. The changes in the ordinance themselves that define the rules, if those change, that would be the kind of thing that would create an increment. A mere change in the mil rate will not.

The State has to reimburse any positive increment to the participant. And the flip side of that is the participant must pay any negative increment to the State. The muni, and this is the -- muni and political subdivision, I'm using those two sort of interchangeably here, they are always going to get paid on the law of the day. If they change their ordinance, that will affect what they get paid. The relationship that's being established here is between the

State and the participants.

The rest of Article 11 deals with a bunch of clauses, a bunch of different things.

The next one is one of the taxes, the nonparticipant reimbursable tax, and that is really focused on two things. It's -- it's focused on the corporate income tax that a contractor pays or on a personal income tax. And what we've done is create a situation which says that if one of those taxes is -- unlawfully discriminates and it is not of general application and it results in a loss, then we will reimburse the -- the participant for that loss.

Generally, I think -- I think -- you know, there is a lot of back and forth about this clause. It showed up in a lot of different forms. Ultimately, I guess, to my mind, and maybe my attorney will jump up here and -- you know, have me not say this, but the notion here is one of the criteria is it has to unlawfully discriminate. So that would have to be proven presumably in a court of law that there was an unlawful discrimination, at which point this could occur.

It's really hard at least for me, it may be easier for other folks, but it's hard for me to figure out how -- how either of these would ever apply, what kind of a situation that could occur, when we were, you know, in negotiations and say, what if a law was passed that, you know, tax oil field workers and nobody else? I guess at least my rudimentary understanding, and certainly all the lawyers concurred with me, that certainly wouldn't pass muster, wouldn't be allowed for Constitutional reasons.

So, at least, from our point of view, we think if it does unlawfully discriminate, then it's appropriate that some reimbursement take place. We don't believe that any -- the kinds of things the Legislature would do, which typically would be lawful, would ever meet this category.

Article 11.6 are time limitations. Basically any of these reimbursements, you have two years -- a participant would have two years to come back to the state and say, I overpaid this or I overpaid that or, you know, this was a targeted tax, any of these kind of calls, basically there's a two-year window. After that two-year window, the claim can no longer be raised.

Article 11.7 contemplates that if a sponsor -- if a participant came to the State and said, gee, this was a targeted tax, I paid $7 million in targeted taxes, we'd look at it and say, well, we don't think that's a targeted tax, we don't think it met the definition. It might be a legal question of whether it changed or not, or it might be a question simply of -- we actually have to go figure out how much the municipality received.

So, let's say, for example, there was a municipality and it showed they collected $20 million in this tax and the participants came forward and showed that they had, you know, $4.1 million in receipts, well, we'd probably say okay, we've got to go audit and find out exactly, did you pass the 20 percent threshold or didn't you do it.

So this puts us in a situation where, you know, the State or municipality is going to be audited. The mechanism we created here was the participant who wants the audit to occur will suggest the names of three independent auditors. The State will then select one of those auditors and work with them in designing the audit, the scope and the plan. The results of the audit cannot reveal taxpayer information, taxpayer confidential information. In other words, they'll come and say, the narrow question was: Did these entities pay more than X percent of the tax collected by this municipality? And they'll answer it one way or the other. And dependent on what that answer is, the loser will pay.

So if, in fact -- if a company came and said, gee, this was a targeted tax, we said, no, it wasn't, went in and audited it, turns out it was, then we end up paying for the audit. If it turns out that we were correct and it was not, the companies who asked for that audit end up paying for it.

Next one is dealing with the whole affiliate question. And the basic rule there and -- is that if -- a participant is deemed to have paid the tax, if an affiliate pays it. And, basically, we're not trying -- I mean, as affiliates are -- are the working level entities when we created the -- under the capped tax, we created the four buckets, the notion is if you have an affiliate and you're looking to see whether you passed your $4 million cap or your $5 million cap, you can take payments made by your affiliates, group them together, flow through, and that's really how you calculate whether you passed that 4 or $5 million.

These aren't necessarily in order. I tried to group them a little more logically than they are in the contract, perhaps. So the next one is 11.10, which are nonparticipant taxes. And the contract is very clear that we are not creating a tax holiday or a tax break, a tax benefit, I guess the word we used in the contract, for contractors or subcontractors.

I mean, just as an example. If I've got -- if I've got a landing -- if I've got a hangar that has helicopters in it, I'm not thinking of a hangar in particular, but you know -- and suddenly half of my helicopters used that year are used for surveying on the pipeline. So do I come and get to say, gee, I don't have to pay property -- I should have 50 percent of my property taxes go away because these helicopters were used on the project, and the answer is no.

The situation that -- what the contract says if -- if what you do is you send a bill on that says, Here's how much we're going to charge you, and here's a specific line item for property tax, then that would pass through to the participant, we would come in and argue, gosh, no, that was just a -- that was just an obligation of the participant and the contract -- excuse me, of the contractor, and the contract very specifically says that the contractors do not receive the benefit of this taxation or this benefit.

The last series of articles -- or, excuse me, the last series of clauses here is a certificate of exemption. Basically, if the State -- this is really focused on if the State has a statewide sales tax. There are things like direct pay certificates, exemption certificates, whatever mechanism is in place, the participants will qualify for, and so if in general folks find ways -- if there are ways that people don't pay sales taxes -- I guess here in Juneau, you can sign up if you qualify for the senior exemption. So, if there's some mechanism in place, the producers will be able to avail themselves of that mechanism.

The next clause deals with the interest rate, 11.11, and incidentally except for some of the oil taxes in which we are preserving the statutory rate that currently applies, in general, we are -- we are referring to a rate -- the interest rates in this contract are symmetrical. It's the same whether it's an obligation due from the producer to the State or vice versa, and it is a -- it appears to me at least to be a more commercial rate, let me just put it that way, than the rate that otherwise would apply for some of the taxes that are being replaced.

11.12 deals with disputes and audits, makes the point that this contract does not govern any local taxes. Those are still done through ordinance, through whatever dispute resolutions, through whatever board equalizations are created under local jurisdiction. Those still exist. However, again, we don't want to put ourselves in a situation where a borough takes a -- you know, a facility that's located in their borough, decides well, gee, I'm going to raise the valuation on that five times. I'm going to send them a notice today, and it's five times higher than it was before and I'm going to collect five times as much taxes. They get it and say, State's reimbursing me. Sure, I'll write the check. So we don't want to create that kind of situation.

So what happens is the State can defend -- can step in in certain matters and basically represent the participant. If the State has an economic interest, the participant has to tell us they've received a tax notice, what they're going to do with it, and we can step in. We will do it at our own cost, but they have to cooperate with us. So the notion is where we are ultimately the -- where the incidence of the tax or the PILT is falling on the State, we have the right to make sure that folks don't take advantage of that, of the fact that the person in whose name that property is -- or that is being levied doesn't have an economic interest in it.

So that's -- that summarizes where we are on Article 11, which I said I'd get through 11, 12, 13, and 14; but Commissioner Corbus asked me to stop at 11:15, so I will -- I guess those will occur after lunch.

COMMISSIONER CORBUS: We have about ten questions, many of which refer to Bob Loeffler's presentation, one of them which refers to royalties, which we're going to be talking about in a minute. So we'll defer the questions until just before we break for lunch. And let's take a ten-minute break now. A conscientious 10-minute break.

[Break]

COMMISSIONER CORBUS: The questions have been piling up, and so we're going to have a slight change on the game plan and -- and answer the questions.

Just an observation on the questions. We've been having a number of questions come in that do not relate in any way to the topic matter that we have -- have before us. And it would be better if we could try to keep the questions pertinent to the topic before us, and -- but we're going to attempt to answer them now.

So I -- will you two gentlemen come up here and sort of divide the questions as they come up?

MR. DICKINSON: I'd actually like to start by answering a question that was asked verbally, and part of this just has to do with how you take a big bite out of this apple. On Saturday Randy Hoffbeck, the State petroleum property assessor and myself will talk about a lot of this in a lot more detail, including sort of the economics of it.

And so the question -- the question is: Gee, why are we reimbursing everybody for all these taxes they should be paying? And the short answer is: When we looked at the gas line, one of the things that has impacted IRR and impacts MPV is the fact that you pay property taxes from the minute you start doing work on the pipeline, and that can be years before you actually get any revenues from it. And so the whole purpose of -- of this was to create a PILT which would be driven by the amount of volume put in the pipeline, it's a PILT -- you know, allowing some of my thunder to be stolen here from Saturday. If the baseline, the 4.5 bcf is the baseline, it's one that economically you can look at, it would come out roughly similar to some of the taxes. If there are the kinds of expansions that we hope for, indeed think will happen, the payments through the PILT could, in fact, be quite a bit higher than the property taxes, if -- if what you do is you tie them to throughput.

So what we've done is we've taken -- when I said that, you know, taxes, direct taxes on the project itself aren't going to be paid, and we go through all these mechanisms to make sure, what we're really -- what we're saying, and maybe I actually should have been clear about that, is the tax -- the payment in lieu of tax will come once volumes are flowing, once cash flow is positive. And it will -- and it will come on a cents per mcf or cents per mmBtu throughput. And so the other shoe, what we're trying to do here in dealing with during construction before cash flow is trying to not have those taxes be an impact on the project.

Next question: Can the production tax be at a sliding scale rate of some kind versus a flat rate of 725? Someone has obviously been reading ahead. The short answer is it could. If we're taking gas, there's probably no reason we want it to be, since the amount of gas that we're taking, you know, you don't want to have -- well, it would depend what the sliding scale would be, but if you've got -- if you've taken a firm transportation commitment, you want to line those up with the amount of gas you're going to be shipping, and so a sliding scale might present problems in that arena.

Regarding taxes paid by producers which are subject to reimbursement by the State, do other pipeline contracts include such clauses? Did MidAmerica or TransCanada ask for such clauses?

You know, the short answer on that is that fiscal stability pertaining to all taxes is indeed a feature of other contracts, and without getting into specifics, I can tell you that both MidAmerica and TransCanada were keenly aware of local taxes, and one of the things that makes the United States different from a lot of projects is -- is our federal system so that there are -- the fact that there are three levels of tax-granting authority, and that's just simply not -- or taxing authority, that's not a feature typically found around the world. TransCanada, MidAmerica working in Canada and the United States were -- were keenly aware of all three levels and having to deal with those in any eventual contract.

How is the Valdez tanker tax handled under the terms of the contract?

The Valdez tanker tax is basically just another fixed payable tax. The reason that there is a page or so of discussion of it in the contract is it's hard to figure out what the status quo is, because on that particular tax, some of the payors of the tax have entered into settlement agreements. Others have -- are still litigating and there are some most-favored nations clauses. So what we're trying to do is create a situation where neither party could enter into a settlement, pay a whole lot in tanker tax, turn around and ask the State to reimburse it. So what we were trying to do in there -- in that situation is, just like with any other fixed payable, if the current system is sustained by the courts, as long as it stays the way it is, the folks who are subject to that tax will pay it.

If it is changed, if it is

increased, then the State would reimburse the incremental difference. If it is decreased, we would be paid the difference with one difference -- with one caveat or one thing that is different from a normal fixed payable tax. If the tanker tax is ultimately -- you know, if there is no tanker tax or, more specifically, if the Valdez tanker tax ceases to exist, the State will not collect the difference. The sponsor group or the participants will not be required to pay the what-if taxes to the State -- if the tanker tax were to go away next year, we would not collect it for the next 30 years. But other than that, it is handled the same way as any other fixed payable tax.

Next question: How will we ever audit all the tax cap increments? What has morphed or not? That's my word, I can't read it. What are the standards of proof necessary to show the State must or doesn't have to reimburse? Is it just limited to the audit in Article 11.7.

No. Going backwards. The Article 11.7 deals simply with the one issue of targeted tax where the State or the municipality is the entity being audited. The -- most of the other audits would go the other direction. The producers would come to us and say, Here's our documentation. We would look at it, and either agree it -- agree with it or not. I guess I'll leave it up to an attorney to answer the question of what standard of proof. I assume it would be no different than any other payment under the contract, whether you'd met the conditions of contract or not.

How will we ever audit all the taxes, caps, TAPS increments? There will be, you know, in -- the net effect of some of the things that are being replaced by PILTs will certainly shift the burdens in the tax division. But there may not be that much more work as a consequence of this.

Next question: In 11 -- Article 11.10, won't all the contractors and subcontractors simply pass on their taxes so that the State will always have to pay?

I guess -- I guess the issue is always going to be where we would argue that, in fact, they had just taken a bill and marked it up and called it tax. We would assert -- and they were, therefore, taking advantage of something that they ought not to, and that might end up being one of the disputes that we'd have to work out. But the contract's clear that we're -- that we're not creating a tax benefit for a contractor simply because they do work on the project.

Next question: Have what-if scenarios been run with regard to impact on State revenues in later years were the State to indemnify one or more of the producers and other parties?

We have not run dollar scenarios and -- and let me focus in on the reason why not. What we have done is looked at the current situation and what is happening now.

We crafted rules that we believe will keep the normal course of business if taxpayers or if taxing entities don't try to exploit the rules on the contract, we believe that that system will stay in balance and will be -- you know, will not involve a huge drop in State revenues or a huge suck on State revenues as we repay all these.

This really gets back to the fundamental point that I started out with which is: If there were abuses or if folks started to, you know, mine the contract, find where they could slip in, do some -- do some back-door revenue sharing that wasn't the Legislature's intent, then the Legislature can act. So fundamentally what we've done is create -- tried to create a situation where those rules -- you know, the -- we're setting up rules that say how the current system works. We believe there's room in there for its natural evolution, but if it veers off course or something happen that's out of bounds, then the Legislature can make that call and change -- and change how those rules are enacted.

I mean, let me not be too cute about this, but, you know, technically, you could simply pass a law forbidding all the fixed municipalities to levy taxes on what are now the fixed payable taxes, and the State would simply get all the revenues that are now going to municipalities. So it's -- I'm not suggesting that, but the point is that remains a power of the Legislature.

Can you give us an example of unlawful discrimination under Article 11.15, the State would have to reimburse for.

Before I hand this to -- to Mr. Loeffler to answer that, I'm going to say, one of the three conditions was unlawful discrimination. The second condition was that there had to be a -- a loss that was provable, and the third one is that it had to be -- I'm stumbling for the phrase, but basically it had to be not broad-based or not broadly applied. So that's only one of the three conditions. I'll put that in your box.

Re: TransCanada and MidAmerica, you said they were keenly aware, but you did not say whether they asked for a waiver or indemnification. Did they?

You know, I probably shouldn't go into the details of the conversation. Suffice it to say that --

MR. LOEFFLER: I'll answer that one.

MR. DICKINSON: Next question: If participants in the contract have certain tax exemptions which are not enjoyed by contractors and subcontractors, is this not a disincentive for them to use contractors? Assuming taxes are included in contractor bid, producers would save money and have incentive to keep work in-house.

I think in general the -- the line -- the balance that we're trying to strike and if we've done it correctly, the disincentive would not be created, is if -- if there's incremental tax being paid as a consequence of the project, then that would be passed through. If simply what we are not trying to do is create mechanisms whereby people by becoming contractors on this project can lower their taxes.

Whoever wrote this question is -- you know, this is something that we are -- we're certainly aware that that's not going to be the most hard-and-fast of lines, and we believe what we've put in in the contractors' language that if that becomes an issue, you know, whether in front of an arbitrator or through re-working, we'll draw that line more cleanly.

Explain how the impact fund will work and how the 125 million will be allocated. What basis will determine allocation? Didn't get to Article 18 yet. It's coming.

When we get there, I'll answer that question. I've got slides on it.

Next question: Why was 20 percent

selected as the starting point for identifying targeted taxes?

That was fundamentally, a -- I'll just say a negotiated number. We had some numbers, and that's the one that we landed on. We did some analysis based on 2005 -- actually, I think the analysis was done, that's right, 2004, taxes and looking at what different entities and what proportion they formed within communities. Is this GAAP? No -- no, there's no generally accepted accounting principle that relates to that -- that number.

Is this consistent, higher or lower, than the percentages we normally see with targeted taxes?

Generally, in the State it would be much lower in the sense that using it not in the defined term, as you're probably aware, the three sponsors pay 85 percent of the tax burden in the State, and on many taxes -- so, no, and the State basically pays for its -- because we as a taxing authority, it pays for it with taxes that are targeted. Those are generally being replaced by PILTs. It is the smaller -- the 300 million, if you will, in my first slide, of nonoil and gas taxes in which the producers do pay a considerably smaller piece, but, I mean, they pay a large portion of the -- of the motor vehicle tax -- motor fuel tax. But again, recall that's grandfathered in. That cannot become a targeted tax.

Twenty percent seemed to be a low threshold in small communities where producers are the large purchasers, employers, et cetera.

I think that's right. And let me -- I mean, if -- to go back to the example, we are not -- a targeted tax is one that will be paid, and then the State will reimburse. So if you had a very small community -- and those of you who are familiar with Alaska taxable know there are places whose total tax take is 20,000, 30,000, 40,000. Let's say a targeted tax occurred in one of those, in such a village, and you might have a situation where targeted tax, we have to reimburse it, but it will be 10 or $20,000. So in a small community, we're not disrupting their ability to levy taxes, what we're saying is if because the project could have such a distorting effect in that community, nonetheless, the amount the State reimburses will be fairly small. That same activity in Anchorage or Fairbanks probably would never hit that 20 percent threshold.

If a municipal -- next question: If a municipality levels a tax that the producers pay and the State reduces the producers, would you call that municipal revenue sharing?

I think I'd just call it back-door revenue sharing, and if that's not the Legislature's intent, they will retain all the tools necessary to fix it.

That's all I have for questions.

MR. LOEFFLER: My turn again. I have been told that if the State uses the 80 percent federal loan guarantee, FERC will only allow the state a very low profit margin as operator of the pipeline. How does that work?

There are about five things wrong with that question.

First of all, FERC will award a rate of return to the pipeline LLC, not to the State, not to any individual stockholder. So it's the same rate of return for the 14 percent on equity or whatever. So the idea that the State gets a separate return from FERC is incorrect, but I will go on to other parts of the question.

The effect of the federal loan guarantee depends on its terms. It's a guarantee of debt. It conceivably could reduce the cost of debt below the cost you would otherwise pay for debt that would reduce the tariff, but it's a straight pass-through. Lower debt cost means there's a lower cost of debt in the tariff. The State is not the operator of the pipeline, that's another problem with that question.

The relevance of the terms can be illustrated by the following: Will the federal loan guarantee kick in once the project is built and you refinance it with long-term debt, if that's the way you go? Or will the Feds be asked to provide a completion guarantee or not provide a completion guarantee on the debt?

If the Feds provided a completion guarantee or a cost overrun guarantee or whatever, that would be taken into account by the FERC in setting the equity rate of return, because the equity rate of return is reflective of the risks that the project sponsors took. And if some of those risks are mitigated by the federal government, that would go into the calculation of what the proper rate of return should be. But it will be a rate of return for the entire project, not -- equity on the entire project, not separately for the state.

Re: Loss, RCA established votes on gaslines or facilitates. Could decisions similar to the ones made in 2002 lead to a loss reimbursable by the State?

Again, if the RCA has no jurisdiction over the gas lines or facilities, the state would not reimburse. It sort of can't get to the factual situation the question assumes. It's similar to the ones made in 2002. If there's a federal decision on rates for the facilities or the gas lines, the RCA cannot undermine that decision. That would be an interference with filed rate doctrine.

And, again, this is not TAPS. That would not occur with regard to an oil pipeline because there's dual jurisdiction on oil pipelines. There's not dual jurisdiction on interstate gas lines.

The State will take all royalty gas in kind. Please provide details of the combination of taking royalty gas in kind and cost advantages and disadvantages. Why only take royalty gas in kind and not a combination?

Well, a couple points. Basically, this is a DNR question. The State has, at a very high level, decided -- high executive level that it wanted to take gas in kind -- all of its gas in kind and go into the business of marketing the gas.

And, as I said before, they saw opportunities and risks there. A combination deal would have had to be -- you might take your gas from one producer and not another in value as opposed to in kind. Or you could take a percentage of your gas from each producer in value or in kind.

Once you move into the in-value world, in part or entirely, you're back in a world similar to what you had with the marketing of oil for the last 30 years.

You have the issues of disputes about valuation, looking at some market basket or indicator as to value. And given the dollars at stake, inevitably there would be litigation on this and the cost and discombobulation that goes with litigation.

One can argue philosophically whether you end up, in fact, better in the in-value world after litigation or not. I won't take a position on that, but the companies and the State were looking for a different way of doing business, and that's part of the decision that went to take all the gas in kind.

In terms of ownership and market share, how did this project compare to others in the U.S.? Is there another U.S. example where producers also control transportation and marketing of gas? Would the State be supportive of an independent pipeline operating -- independent entity operating the pipeline?

First of all, in terms of ownership, we couldn't find any case where a state has taken an ownership position in a interstate gas pipeline in the United States. And I think no one could think of one.

Either Wyoming or New Mexico talked about doing it as part of the Enron debacle but did not go forward with that.

In terms of market share, you have to separate in a proper antitrust analysis what market you're talking about. There's a market for the sale of gas, which is a huge national market. The producers' proprietary shares in that market are too small to have market power as my partner explained, I think, on Monday.

There are a number of cases where new pipelines have been designed and owned initially by the producers. I think Alliance is one, I believe Maritime of Northeast is another, and I can provide -- I can check into others.

So there are cases where producers involved in the design and financing of the pipeline so they could get it the right size, right conditions for their gas. And then they often sell out after they got the thing up and running. So it's not uncommon.

Would the State be supportive of an independent entity operating the pipeline?

I think the State is supportive of whatever gets the project built. And the State looked at sort of the competitive issues that's analyzed in the fiscal interest finding, and is comfortable that -- or believes, really, that this is the best way to get the project built.

On June 2nd the district court in

Fairbanks will hear arguments in the AGPA antitrust lawsuit against the Big Three. How would a ruling favorable to AGPA affect this project?

First of all, my understanding of what happens on June 2nd is that -- are arguments on the producers' motion to dismiss. If they win the arguments, the case will go up to the Ninth Circuit, because the case will be dismissed. If they lose the argument, all it means is that you proceed to the next step in the litigation. It's just a first shot in the case.

You will not get -- it is beyond reasonable possibility that on June 2nd there would be a ruling favorable to AGPA that would affect the project. That comes a long way down the road. I've seen testimony by Mr. Boyce that ultimately the AGPA is seeking a mandatory injunction that would require the producers to sell gas to AGPA and no one else. But that's a long way away.

Please define the status quo when discussing Alaska revenues to be received under the contract.

Pedro's going to be back, and I

think that's a Pedro question, as is the next one. I'm not an economist.

What impact to the internal rate of return would there be on an Alaska take if the 35 percent GTP and feeder line credit were slightly reduced?

Well, as I said yesterday, we've got to see if the credit emerges from the -- in the new PPT legislation. And then we can analyze the impact. But I don't -- I don't run economic models.

Payment of loss is subject to appropriation by funds from the Legislature. Why does the Legislature's failure to appropriate not create a dispute?

You've got to turn to page, I think, 213 of the contract, and it's 37.3, which I hope to get to this afternoon. It says -- first of all, it's a contractual term. The Legislature's failure to make such an appropriation does not create a dispute. It does not distinguish the underlying obligation to which the appropriate -- for which the appropriation is sought.

The answer is: We didn't want to

get into a dispute on what the Legislature does or does not do. So that was excluded from the contract. The Legislature has its own prerogatives. And, secondly, if there were a dispute, it just would be circular, because it would end up in an award that would have to be paid by the Legislature or offset within the contract. There's already recoupment under the contract. So it just would be an unnecessary step.

I have a force majeure question which I promise to get to when I do force majeure.

If a 35-year term preventing a change in tax laws is determined to be unconstitutional, are the producers relieved of any obligation to build the pipeline, and how many?

There's an option there. There's a clause that addresses this about a judicial challenge. I could answer that this afternoon.

And TransCanada and MidAmerica, we've been advised by counsel that we should not talk about what happened -- the substance of what happened in those negotiations. So, I can't answer that last question. I'll tell you what it is.

You said they were keenly aware, but did not say whether they asked for waiver or indemnification. Did they? Really, respecting the confidentiality of those negotiations, I can't answer that.

I can say, and this is a matter of public record, there never was a contract with either of them. There was something like a memorandum of understanding with TransCanada, but that is not a contract. And there was not a contract with MidAmerican. So, a lot of the questions that Dan and I have addressed arise sort of along the way when you try and put things down in a contract. Since we never got there, there isn't that much to say.

COMMISSIONER CORBUS: Thank you, gentlemen. It is now noon, and we have got a very -- a lot of subjects to cover this afternoon, so we'll come back at 1:30, and please be prompt. See you then.

Thanks.

[Lunch break]

COMMISSIONER CORBUS: Would you all

please take your seat so we can get started?
Thank you.
Can we please have the meeting come back to order?
Dan Dickinson is going to continue on with his description of provisions 12 through 14 of the contract.
We will go for about an hour and then take a break, go for another break, take another break, and we've got a long -- a long day ahead of us.
Dan.
MR. DICKINSON: Okay. I'm the beginning of a long day ahead of you. And I just thought I'd correct the fact it was not "Fools" that was here on tour here in 1984, but "Tartuffe." I checked the posters out in the lobby, and when "Fools" came here, it was in 1982, and it was out at the theater that's subsequently been razed.
With that correction, what I'm going to do next is talk about Articles 12, 13 together, and to do that I'm going to skip ahead. So, if you're looking at your packets, I'm skipping slide 18, going to talk through 19 and

20 and then go back to 18. These got ordered incorrectly. I basically just want to use the two graphs that are there to, again, to frame the issue of the dollars of what we're talking about here.

Estimated gasline revenues, Table 8 from the fiscal interest finding. The large piece is the dark blue. It's three-quarters of the revenues, and they will come about as a consequence of selling gas, and provisions 12 and 13 are about how the State gets its gas.

On the next slide, again, just to continue that perspective, that three-quarters that results in our current revenues is also from production taxes and royalties, and so this really is the biggest piece of what we're talking about here today.

So, going back to slide 18 and -- okay for some reason, I guess I'm one off in my numbering, so something has happened here. But going back to this slide. I think this has been dealt with in more detail by folks from the Department of Natural Resources, but I would like to just go through it briefly, particularly as it lines up with slide 13.

Article 12 deals with our royalty. 12.1 says the method of the royalty payment and the method will be that the State will take gas in kind. There are things call incremental royalties will deal with net profit share leases, sliding scale royalties, other enhancements to the -- to the core royalty. Those -- the terms on those will be identical to the terms in the lease. There is one area in which there's an option in the lease, and that option has been important to the contract. But in general incremental royalties will be in cash as they are under the lease and if there's an option under the lease then we would still have that option. But, fundamentally, it is the core royalty that is in kind, and the incremental royalties remain in value.

Article 12.2 essentially restates that. 12.3, it goes on to talk about the example -- the one payment and sets out some principles for taking of gas, and those are similar to what we see in tax gas.

The principles here are under 12.4, and it says: The title transfer of royalty gas and disposition of gas and impurities. And the main point here, the State will take delivery and title at what's called a delivery point. Probably should have been capitalized and italicized here to take the convention of the contract. But the delivery point into the main -- midstream element. And when that occurs, there are some general principles about what that will mean as the parties figure out their commercial rights.

What's going to happen with that disposition of gas? The first thing is that all parties have the same rights, privileges, and obligations in their gas. In other words, at that point we have take our gas and we stand just like any other commercial partner who has -- who owns gas which they are -- are moving through those midstream elements.

The second point is that no party may unreasonably interfere or require the installation of special facilities. Again, I think the concern there is about the State taking on a role as a regulator or looking at overall economic development as opposed to simply having the same rights as another commercial entity who wants to do -- have special facilities built or not be required to pay for them if they would benefit a different party.

And, finally, a party may authorize another person to act on its behalf. And the notion there being, again, particularly for the State, among the situations -- and I think the folks from the Department of Natural Resources have gone over this with you -- among the things we may do is transfer that gas at that upstream point to someone else who would be handling either the marketing arrangements or would be taking it on for their own uses.

The next article -- which is probably not Article 12.4, so obviously I was doing that very quickly, it's probably 12.5 -- deals with the title transfer of the royalty gas -- excuse me, it is a continuation. The disposition of gas and the impurities. It's the second piece, and it deals with the disposition of impurities. I think Bob talked about that a little bit already.

The notion here is each party is responsible for its own impurities. At the gas treatment plant, CO_2, H_2S will be stripped out, and the State will have to do something with its

CO_2 and its H_2S.

Presumably, everyone else will, and we will be treated -- under this contract, we will be treated the same as those parties. If the -- if the impurity is disposed of in what's called a disposal property -- and this is really another way of saying if the gas is put back into the ground at Prudhoe Bay -- we will treat it as indigenous if it's from that property. In other words, it will be treated -- the next time it shows up, it will be treated just like it had always been Prudhoe Bay gas, and if it has some other origination, if something else is done with it, we will be treated the same as other owners.

So these principles of disposition of gas and the disposition of the impurities apply both to tax gas and to royalty gas.

So, moving on from Article 12, we move to Article 13, which is the tax-bearing gas payment. And that starts out on 13.1, dealing with what happens before CoCO, or the Commencement of Commercial Operations, and there's a tax-bearing gas payment. In general, what's going to happen is North Slope gas will be PPT gas; or, in other words, it will be -- it will be dealt with -- with whatever production tax statutes say.

This notion that the State is going to start taking its gas in kind doesn't start until the commencement of commercial operations of the project. There are a couple of exceptions to that. The first one is what happens if gas is injected into another property? And the scenario here that you might think about is let's assume the project's going forward. Oil prices are somewhat like they are today. Folks will look at Point Thomson, and say, gee, we are going to develop Point Thomson. Let's get that sucker going in a couple of years and we can at least get the oil into TAPS.

So you might see Point Thomson happening on a accelerated schedule. What are they going to do with all the gas that comes out at the same time? Well, you might not want to put it back into Prudhoe -- into Point Thomson, maybe they'll want to put it into Prudhoe Bay. There's various things that could happen with that situation. We won't have reached the point of commencement of commercial operations yet, there will already be a bunch of gas that has to be dealt with. So what we basically said in the contract is if that gas is injected into another property we will be treated the same as anyone else.

I think as DNR's emphasized several times in their presentations, you know, we have to say we're just like another producer in lots of places, because, in fact, we're not. And generally the three sponsors that we're dealing with here have ownership rights, particularly in -- in Prudhoe Bay, they're different than Point Thomson. There's going to be a set of commercial arrangements. They're going to reflect the fact that it's not a -- if it's a cost to Prudhoe Bay, ConocoPhillips, for example, will want to be compensated by Exxon. If Point Thomson has caused these costs to be incurred at Prudhoe Bay -- and what we're saying is we need to be treated as anyone else in -- in those situations.

The second exception is the line pack. Technically, it will not be commencement of corporational operations, but there's simply an amount of gas which in -- you know, at least from an accountant's point of view, an inventory accounting, it's essentially, like a LIFO. You basically fill the pipeline up with gas, and then from then on, you put something in at one end, and you take something out the other, and you sort of ignore and you pretend there's sort of a solid body that stays in. And then you don't really deal with that until the very end of the pipeline's life, at which point there is that set of gas.

So there's something called line pack, and what traditionally will happen there is the pipeline will go out for a bid, ask a producer for a price; they will purchase that gas, and we will simply sell at that same price our 7.25 percent.

13.1 goes on to talk about what happens after the commencement of commercial operations. In that case, and this is going to be what, you know, 99 percent of the contract is about, we hope. We will be receiving 7.25 percent of the gas, not counting royalty, in kind at the delivery point. And, again, let me -- let me focus in on the -- on the after royalty piece.

Right now under production tax statutes, if the -- if gas or oil is produced from state land or federal land, we only tax the portion that is not royalty. So if -- if royalties were 12.50 percent, what I think in the shorthand you hear us using a lot is only 7/8th is taxed, not 8/8ths. The last 1/8th is not taxed. By the same token, we would receive 7.25 percent. If we go out into a situation like to NPRA, we will not be getting our royalty gas, but, again, we'll be getting our tax gas.

There are two exceptions -- there's actually -- once we're in commencement of commercial operations, there is one additional exception. And this exception -- and the same exception shows up in royalty -- is if less than 95 percent of the gas is going to the project, the State can basically look at that alternative use and treat it differently. So, let me again back up.

What's going to be happening is we are going to be taking our royalty and our tax share in kind. Now, as you're probably aware, on the North Slope today and after a major project there would still be minor sales. There are sales at TAPS. There are sales to Norgasco and other industrial users. So there's a small amount of gas being transacted on the North Slope now. We tax it. We take our royalties share of those sales. We look at the value of those sales. Under the contract that would no longer be happening, everybody would get their share of the gas. The producers, if they choose to make those sales, they could make it out of their share. The State could bid on that. The State could be a, you know, supplier of fuel to TAPS, or to the Park Industrial Center or anything like that. The point is everyone gets their gas, and then they make their decisions about how to dispose of it.

Our condition was if something arises so that we have more than 5 percent, and that's like -- that's like 200 million cubic feet a day. It's a huge amount of gas. If more than 5 percent is going to another project, three consecutive months, there's a test there. So, if there's a sudden breakdown or something, this doesn't trigger it. But, fundamentally, if the producers find a more valuable use for their gas than going into this project and it reaches to the threshold of more than 6 percent of the gas, we come back, and we have these four options.

The first option is we can look at that and say, Fine. We can say fine, we'll leave it as it is. We'll still continue to take our 7.25 percent. You do with it what you want. That would be a fee -- if it were a less valuable interest or a marginal or we had contracts or for whatever reason, we could simply continue to take our gas. For whatever reason, we could simply continue to take our gas.

I'll get to it later, there's actually some formulas, which value tax gas. We could insist that we be paid in kind on those formulas. We could treat it as PPT gas, which is, again, shorthand for saying we could simply go back to the statute which if it -- if it looks like the statute that exists today, says we find the value of it, we calculate a percentage of that value and tax it in a very traditional way. Or the last bullet point there, it says: We can make other arrangements. But the -- but the point is we have the option of going to these. We don't necessarily have to go back and be taking it in kind.

So, which of these we do is open. It's hard to imagine what the situation will be that will trigger this. So that's why we had that fourth -- fourth bullet point in there. The point is the producer can't say to us, no you need to stay in the current relationship, you can't go to one of these other relationships.

Again, I've spent a whole lot more time on that than probably will ever be necessary but once the project is up and running, folks will be free not to put gas into it. Obviously, they'll want to do whatever they have firm transportation commitments for, but if you think about expansions or things like that, this clause might be triggered.

Article 13.2, again, kind of moving along with the royalties says: If reinjected impurities are treated as indigenous, then those molecules may be subject to multiple tax-bearing gas payments. Again, all that's saying is as, as gas comes out of the ground and CO_2 is stripped out, if it gets reinjected in Prudhoe Bay, when it comes up a second time, we will also get our 7.25 percent of it as it comes around a second time.

The next four articles, and, boy, this is a real disaster to try to do this right after lunch. Because I was going to have everyone do a math example here and walk through here with me, but I guess won't.

Articles 13.3, 4, 5 and 6 are just a series of formulas. I won't ask anyone to actually try to work these through, but what this does is defines the tax-bearing gas value as the volume of the tax-bearing gas times the heating value times the tax-bearing gas price. 13(b) then says the tax-bearing gas payment is the tax-bearing gas value times the tax-bearing gas percentage. 13.4 defines the tax-bearing gas percent is 7.25 percent. 13.5 goes on and says the tax-bearing gas price equals the AECO price less the Alaska-to-Alberta tariff. And 13.6 says the State's share of the tax-bearing gas is the tax-bearing gas payment divided through by the tax bearing gas price divided through by the heating value.

Okay. What does that all mean? If you do the algebra and you do the substitutions, it all cancels out. It's kind of like that game, I know, you play where you start to name your birthday, and you do this and you add this and do and 27. And somehow you sneak in a division through by zero and you also come out with the same number. Fundamentally, when you've done all that substitution and math and get through, you get the State's share of tax-bearing gas equals the volume of tax-bearing gas times 7.25, times A, times B, divided through, by A, by B. And as an astute -- someone who did the math would say, gosh, you know, buried deep into Exhibit A.3 you will find that if B turns out to be zero, you would be division through by zero, so it would be meaningful -- meaningless. We used the number, $1.25. But the point is we go through those steps to arrive at, arithmetically, the fact that the State's share of the tax-bearing gas is 7.25 percent.

The reason for these steps have to do with -- with a complication that, as you're probably aware, one of the -- one of the things that producers that were entering into the contract will be booking a huge amount of gas when this becomes commercially viable.

When a producer books gas, it cannot book its royalty gas. Cannot book royalty gas because that doesn't belong to the producer. That's part of the State's, it's part of the commercial arrangements by which it's producing it. And I think there's a big concern that the SEC might look at the tax gas and say, gosh, that never was your gas either; we're going to knock your reserves down by another 7 percent. So what we've gone through is an option for a tax-bearing gas payment that creates the situation in which the producers will -- will, you know, meets the necessary requirement for them to show that these are not, in fact, gas reserves -- excuse me, they are reserves, they're not royalties, they're not like royalties. The State is making an option under these formulas to take its share, its 7.25 percent, that it would have of tax-bearing, the right to assert a tax on that and, instead, is taking that in kind.

13.7 are the example calculations. And Article 13.8 deals with a title transfer of tax gas and the disposition of the gas and impurities, and they are the exact same principles. In fact, it doesn't even have new words. It just says, Go back and look at the royalty section, and those same principles for disposition and impurities apply for the tax -- tax gas. At that point, we are the owners of that gas, and these are the rules that are going to apply. That's Article 12 and 13, which are the sections under which we get our gas.

Article 14 is a very short article at the moment, and it's dealing with a payment in lieu of production tax, and it says, gosh you'll figure it out according to the terms of Exhibit P. And if you went and turned to Exhibit P, you found a page, I forgot what the exact message was, but it was a one-liner that said not yet. But the two things -- there are two things that are established here in Exhibit -- in Article 14. The first one is the revenues, the cash flows from this PILT will not be in the waterfall, and that's kind of shorthand. When I get to Article 22, you'll know exactly what I'm talking about. But until project sanction this -- this will not apply, or there are some of the terms of the contract that will not apply to the -- the cash flows from the PILT and payment in lieu of a property -- excuse me, in lieu of the production tax.

The second point is is that the term for this particular article is for 30 years unless it's extended by mutual agreement. So, fundamentally, I think the view is if it's working, if it's producing the kind of revenues that folks are, you know, believe are appropriate, it may go on. It may go on the length of the contract. But if either party says it should not, after 30 years they can pull the -- pull the plug on that particular section.

Moving along, I'd like -- the next two slides -- again, it's just going to be showing you slides you've seen before, but just try to put things into perspective. The next five or six slides are going to be dealing with the property tax payments in lieu of tax. I'm going to go through those very quickly. The point is that we will be spending more time on them on Saturday day, both the economics and the mechanics of how those work. But, again, as you look at this chart, you will see that there's a sort of two -- two small slivers that together constitute about -- about 4.5, 5 percent of the total that constitute about $6 billion, which are what compromise the upstream and the midstream payment in lieu of property tax.

If you skip on ahead and look at -- at local tax revenues, what you will see is right now the oil and gas property tax is the second largest wedge up there. It's sort of the light blue in the upper -- upper right-hand corner, and that constitutes about 20 percent of total taxes -- excuse me, total local receipts -- total local revenues. And just to give sort of a perspective on that, the State gets about an additional $45 million in property taxes, so the total oil and gas property taxes are about a quarter of a billion dollars now, of which municipalities get about 210 and the State gets about 45.

Article 15 deals with upstream facilities payments, which are the payments on the upstream facilities, but there are two. There's an upstream facilities oil payment and an upstream facilities gas payment. This was a -- a topic of quite a bit of conversation with -- with the sponsors about whether there -- whether the consequence of adding gas added to the value was an appropriate way to model this. Ultimately what you see here is the result of those conversations.

On the production facilities, that is, literally, the Prudhoe Bay unit, the Kuparuk unit, the Badami unit. Taxes are levied now. And right now we are in a period -- what we have tried to do is use through puts to determine the -- the value. How much oil -- how much oil flows through each production facility is used to determine the changes in value. In other words, the base line is still based on cost. And, of course, because these facilities are, you know, approaching 30 years old, it's costing, sort of the assessor's term of working through a lot of things and changes that might have occurred, inflation and depreciation. But once you sort of establish that level, and then every year, if production is more than anticipated, the value of the facility goes up a little bit; if it's less, it goes down a little bit. So we have been doing that for approximately three years. It's certainly authorized by the statute. It's not something that had been used up until today, or up until three years ago. Fundamentally, we had spent a lot of time arguing with producers about values, year-to-year changes. And this was a method that makes sense for the producers who are paying the tax for the municipality of the North Slope Borough who is getting a great deal of this tax and for the State as well.

So what we're really doing on the oil payment, the payment related to the amount of oil that's being produced, is that is pretty much maintaining what we have started and done for three years, and everybody seems to think that it is a -- it is a good reflection of what is going on. The one thing that differs from the current status is that we have also built in an inflation component for a three-year test. Inflation isn't particularly rampant these days. We have -- for that three-year test period, there was no inflation factor. If we're looking at a longer period, we've built in an inflation factor.

Interestingly, one of the indices that folks look at for inflation is what's called Marshall & Swift, which looks at just oilfield services, and because of the prices, a lot of oil field services and things like that have been in high demands, the inflation factor for oil field goods and services was, I think, 8.3 percent last year, which was about four times higher than the inflation rate as measured by the CPI.

Anyway, I'm getting way ahead of -- or giving you stuff you're going to have to sit through again on Saturday. What we have here for the facility, and, remember, it's the same facility, the Prudhoe Bay unit will be charged about 50 cents a barrel for every barrel of oil that comes out through that facility, and about 2.1 cents for every mcf that comes through. As gas -- as oil volumes fall and gas volumes rise, you'll simply have a shift between which of those two is the dominant form of the payment.

As I said, I promised, and I won't try to explain all of these, because we'll go through them more later. But 15.3 deals with determinations of volumes. Instead of looking at it year to year, we have an average of several years. 15.4 deals with cease production, what happens if like at Badami you shut down for a few years, and then you start back up. How do you do the averages?

15.5 is annual payment. And the interesting thing here is that what the rules here say is, if the effective date of the contract is after June 30th, then the payment for 2006 will be under law, and these provisions won't kick in until 2007. Again, just to remind everyone, the way the world works under the law today is, valuation date is January 1st. So it's the property that existed where it was on January 1st. We go through the process of valuing it. Go through appeals, and payment has to be made by June 30. Last day of the fiscal year, and, yes, at one point, several years ago, it had been moved from July 1st back to June 30, because people needed some money that fiscal year.

What this is basically saying is once the munis have figured out -- know what they've done, issued their mil rates for everyone else, if the contract comes up with a different value than you saw in the mil rates -- excuse me, in the calculations the municipalities have made this year, it simply won't be effective. So it certainly appears given what the -- what the -- you know, the schedules that had been laid out for public information and everything, the contract will not be signed before the end of June, so then this means this 2006 will be under law. 2007 is when the contract will come in.

15.6 gives inflation adjustments for oil and for gas. 15.7 deals with third parties. Basically, if Conoco Phillips is the operator of the Prudhoe Bay unit and, you know, the three sponsors constitute 97 or 98 percent, we still have to worry about the other couple of percentage points of ownership that weren't affected by this contract, and this basically says that those will flow through. We will assert the tax. The operator will still act, essentially, as a tax collector if you will, for us on those -- for those other pass-through entities.

A lot more detail will come on Saturday.

Article 16 is the midstream payment. This deals with the three -- with the elements that are being built in this project. The main one, of course, is the gasline, but a secondary one is the GTP which will be a several billion dollar facility at the very front end of the gasline and. Furthermore, we have gas transmission lines. Clearly there will be one coming in from Point Thomson. I think it's everyone's hope and expectation that there will be sufficient gas found at NPR-A. There will be another line coming in from the west.

And the basic starting point of all these calculations, again, is throughput. For the main line, and this is after the impurities have been stripped out of the guess. The payment will be 2.4 cents per million Btus. For the GTP as well, it will be 1 cent per million Btus. For the gas transmission lines, because all the stripping out of the impurities will be happening at the GTP, the gas transmission lines, instead of being on mmBtus, it's being measured on mcf. Mcf, for thousands of cubic feet, the right is .0003 cents per mcf-mile. So, you go in. There's a whole set of calculations, that you figure out the length of it and the number of miles that each mcf travels goes into the calculation.

Article 16.2 deals with the determination of the midstream payments, quantities, volumes. 16.3, again, this is sort of parallel to what was happening back in Article 15, deals with ceased operations, what happens when the pipeline goes out of service, comes goes back in. 16.4 was an annual payment. Of course, we don't have to worry about law of the day because none of these facilities are currently existing.

16. 5 is the inflation adjustment;

adjust. 16.6 is an additional midstream facility. And that simply says, Here is what the projects looks like now. If something else gets built, we'll have to sit down and figure out what, if any, the PILT on that is. The point is, it's not that these are the only PILTs that will exist because this is the plan, as the plan changes, so, too -- you know, it's acknowledged that the State's share on this particular mechanism may change as well.

Article 17 deals with payment in lieu of oil pipeline ad valorem taxes, and part of the reason why this has been split out the way it is, Randy Hoffbeck, who is the state petroleum property assessor, is literally up in Anchorage now dealing with an appeal on the valuation of TAPS, the third such appeal in five years. It takes three or four days. A lot of experts get together in a room and hash it out. And we hope that once this contract is passed, that -- as much as fun as I've had at some of those, they will be a thing of the past.

What this does is this, again, sets basic rates. The base line is set based on cost and the cost principles by the statute and then the amount that it's going to change every year is driven by two things, excuse me, inflation and the throughput. As the -- as the -- those are the only two drivers, and we don't have to deal with some of the -- some of the thoughts and things that I've come to love about excess capacity and utilization adjustments and all the things that go into a good assessment.

So, Randy will talk about this a lot more when he is here on Saturday. But just to go through it very quickly, 17.1 sets out the payment. 17.2 goes through and for each pipeline, based on its cost says what the cents per barrel throughput is.

17.3, again, how we actually define those volumes. 17.4 deals with ceased operations. 17.5 deals with what happens for a pipeline under construction and that basically goes back to the way it's always been which is if I'm building a pipeline on January 1st, it's a stack of my receipts, what have I spent so far. That's what gets taxed. 17.8 -- 17.8 really deals with the tax billing and reporting. Again, because of the notion that some of the owners of some these pipelines may not be signatories to this agreement, we're still going to have a pipeline that could be paying some PILT and some tax. And then 17.9 deals with, again, this notion, 30 years. This is -- these PILTS will stay in place for 30 years, but they may be terminated at that point by either party. If they don't, if everyone's happy, then they will continue on.

I just am --

The next article is Article 18, and I know I had a question here, but I hope -- I'll cover it anyway, and those are impact payments. One of the things -- points I'd like to make about these impact payments, because I frequently hear them mischaracterized. And this gets back to one of our themes here. While these are meant to -- to account for -- address economic and social impacts, and they in some sense are modeled to deal with the property taxes that are not being collected, these are payments to the State. The dollars go to the State. You folks will then appropriate them to wherever is necessary, either directly to a municipality, because that municipality is experiencing impacts or perhaps if the world looks anything like it does today, it will be spending the State undertakes in the unorganized Borough.

So the point is this $125 million is State money to be spent on impacts. The -- the dollars come to the State. It's $125 million over six years following the project sanction. The other observation that I put up here is, by that time the folks -- you know, we will be us, or something. The State, it is the pipeline entity that will be paying this -- these dollars, and the State will be a 20 percent owner, and so in some sense, 20 percent of this $125 million is -- is us moving dollars from one pocket to another.

The schedule set out in Article 18.1, $9 million in sanction, basically a schedule goes over for five years. Total of $125 million. The inflation adjustment on this is that if -- if, in fact the work continues at the -- at the rate that folks anticipate, these would all be dollars of the day. There's no adjustment.

Once you move beyond nine -- nine years from the effective date of the contract, then they become inflated. So there is already a level of inflation built in and if, in fact a project gets slowed down, we will have to inflate what's left.

18.3 deals with the suspension or termination of the obligation. Some of the conditions that Bob was talking about about what happens if there's a -- a temporary suspension, basically, if that suspension lasts for more than one year, then the -- then the payment that would occur in that suspension does not have to be made. Once you start up, payments do have to be made, and there are no obligation for payments not made at termination, but if you -- if you follow through the words of the contract, if, in fact, the contract -- the pipeline gets built sooner than we'd anticipated, so from sanction until first gas is -- is a shorter period of time. The additional payments will still have to be made. So the only reason that all 125 million wouldn't be made is because the project has terminated.

Once again, a slide that you're familiar with, I'm about to get into corporate income tax. Bill, should I go ahead -- one more.

COMMISSIONER CORBUS: Yeah.

MR. DICKINSON: Okay. Corporate income tax, again, in this slide it's the SCIT piece, the light yellow, it's the second largest slug up there at about $14 billion. And if you look at today's revenues or last year's revenue, again, it's the kind of the reddish triangle in the upper right-hand corner, but the point is, it is sometimes overlooked. But -- you know, last year it was a half billion dollars came in as a consequence of corporate income taxes, as compared to production taxes of about 900 million, so smaller but nonetheless a significant -- significant portion.

What I -- what I wanted to spend a second doing is reminding folks about how the corporate income tax works. What we do is we look at worldwide income, and then apportion that -- apportion that to Alaska. So, once you've -- once you've accomplished -- once you think about income, a dollar of income which you might think is earned in Alaska, or a dollar of income -- if you look at it and say, well, that was obviously earned in Azerbaijan, they all go into a bucket, and then they get apportioned to Alaska.

So the difficulty is when you think about incremental costs or incremental benefits or incremental spending, one dollar of additional costs in Azerbaijan or in Alaska have the same effect on the total tax paid. One additional dollar of revenues in either place has the same effect. What matters are the three factors that are used to apportion income from the worldwide basket down to Alaska, and those are -- the three factors are sales, which is very small, as you can imagine, because -- for most of these companies, the Alaskan sales, which essentially are just their pipeline tariffs now, are very small compared to worldwide sales. So that's typically a number that has several zeros in it before you start reaching the significant digits. Very small factor for sales but then the other two factors, one is production, which is very hefty even for companies like BP and Exxon Mobil, Alaska forms a significant portion of their worldwide production and property. Which, again, Alaska forms a significant, less than production but more than sales, portion of their total worldwide.

So those three factors generate how

much -- figure out from those how much of your worldwide income will be attributed to Alaska.

Basically what we do in the contract is we say, In place of SCIT, which is the acronym for the state corporate income tax -- I don't know how we came up with that acronym, because we actually prefer ANITA, which is the Alaska Net Income Tax. That sounds so much smoother. But SCIT kind of has a harsh edge to it. But the payment in lieu of SCIT will be essentially what it is today, simply going through a process of freezing some aspects of it.

What we do is we adopt the -- the existing Alaska code, the existing Alaska statute, we say, that's now going to become part of the contract. The words aren't in there. The contract says you go and look at it as it stood on the effective date. That becomes part of the contract.

Now, what that Alaska code says is we are adopting the federal code. So what's happening is, we have frozen the State rules which embody the federal rules so the federal rules can continue to change. In other words, what nobody wanted was that we had to keep one set of books for Alaska rules as they existed -- Alaska and federal rules as they existed in 2006. What's going to happen is we are going to continue to -- federal rules will continue to flow through change as the Feds change their income tax rules. The trick -- the reason that a lot of the words, it takes a lot of words to do this is because of sort of this dual concept of freezing something which isn't frozen.

We are also going to have the same effect on State judicial interpretation. As those have applied to and as we have continued to apply the tax and have court orders, court rulings on that. If those had occurred before October 1st, 2005, they will continue to have -- they will continue to be probative of the amount of PILT payment now, no longer SCIT, but the amount of PILT in lieu of SCIT. However, if a Judge rules on an income tax case that's not -- you know, next year or the year after, that ruling will not affect the -- the payment in lieu of SCIT. We will adopt federal court rulings, and there's a whole hierarchy, because, again -- I hope -- the lawyers will kick me if I'm getting this wrong. Obviously, if the Ninth Circuit rules that that has certain weight. If the Sixth Circuit or the Second Circuit rules, judges may look at that but it may not be as probative. There's a whole hierarchy of how we figure out which decisions will apply, which federal decisions will continue to apply in the administration of this payment in lieu of SCIT.

Articles 19.2, 19.3, and 19.4 deal with the apportionment factors, which are -- which are the factors again that we use to apportion worldwide income to Alaska. And, again, there's been -- there's been several -- there are several misstatements of this, one of them, in fact, unfortunately is in the examples in the contract itself. What these -- what the rules say here is that certain transactions arising from this contract will not be part of the numerator in those fractions -- numerator in those fractions. It will not drive income to Alaska.

And the specific thing it mentions is 19.2, the tax-bearing gas payment will not be considered a scale. It won't be part of the numerator in the sales factor, the upstream cost allowance which I'll get to in a couple of minutes, or couple of hours, maybe, will not, again, go into the sales factor. And a field cost allowance, if there is any such thing, will not go into the sales factor.

The point is, that these are no change from the current practice. The current sales factor, like I said, is like a zero zero zero something and basically are the sales that are made for the -- for the tariff, for the TAPS tariff, and as such this is -- this is not a change. So this is not something that we would be subtracting from the numerators, all this is saying is this forecloses someone from arguing, state auditor, for example, coming down and arguing that those -- those are like a sale and those should be added to the numerators in the apportionment factors.

19.5 makes the statement that the payment in lieu of SCIT is a tax on or measured by net income. And, again, all of this really gets into is -- is freezing current practice and -- and the calculation of worldwide income. And just to -- not to get too deeply into it, but basically when we look at worldwide income, we're trying to look at it before income taxes of various other jurisdictions have been deducted from it. So, when you look at worldwide income, you have to add back any taxes measured by that income that. And that sometimes can be a contentious practice, and so we just -- the parties all agreed that this was a clear statement of what was going on there.

Article 19.6 deals with fundamental changes to the federal income tax system. You know, there are many folks who find the current system to be terrible, and there are lots of solutions that have been proposed to it. I don't think any one of them have gained critical mass, but if this is going to go on for 30 years, it's entirely likely that there will be a fundamental change. It's really anyone's guess as to what that could be. What we have proposed is if that occurs, both parties will propose an alternative for this payment in lieu of SCIT, which will somehow measure the same kinds of things and if we can't agree on it, there will be an arbitratable issue about how to reconstitute this SCIT or this PILT, and we're also, I guess one of the other things that an arbitrator would look at is to make sure that this does not -- it will hopefully rely on something else and not require the creation of a whole lot of independent books and records just for it. In other words if there's some other thing we could look at, if, for example, under generally accepted accounting principles, folks still might be required to report a profit. The number of elements are different, but the underlying basis is the same.

This just really tries to deal with what happens if in the period of -- well, 45 years for a portion of this, there is such a fundamental change in our tax system. The income -- barely -- the income tax is barely 100 years old, not quite 100 years old, so this is looking at sort of a third again of it's length -- of its entire history. So the notion there might be a change there, something we thought we should try to account for.

Article 19.7 deals with the tax periods prior to the effective date. And the point is this has no effect on it. Some of those are in various stages of appeals or audit and those will just simply stay under the old rules, none of the new rules having effect on those periods. On the other hand, unlike the -- the situation that I just talked about in the property tax, if the -- in the year of the effective date, and let's assume, I think for this would be 2006, what will happen is the payment in lieu of SCIT it will apply for 2006, the quarterly payments that were made, and there would still be -- quarterly payments would still be required, will simply be considered payments now for the payment in lieu of SCIT instead of for the SCIT. So it essentially becomes retroactive to January 1st.

Article 19.9 deals with the term; and, again, we have a 30-year period. After 30 years the parties can elect to limit the application of the corporate income tax to projects -- to either the project or gas from a property as those are both defined in the contract. The thing that gets really tricky here is corporate income tax is based on -- you know, you have a unitary entity and they earn an income and people haven't tried to figure out how much is driven by this or how much is driven by that. So the notion of saying gosh, we're going to have an income tax on gas but not on oil isn't necessarily a trivial problem to solve.

It -- it can be done in the sense of you could create fairly arbitrary standards and say we're going to allocate it, we're going to divide it up this way, we're going to divide it up that way. But it isn't necessarily clear what would happen when you say the payment in lieu of SCIT will just refer to one source of income and the payment -- then the payment in lieu of taxes will be something else. It will be particularly difficult -- let me put it the other way. If, in fact, the law doesn't change for 30 years, it is a much more solvable problem. Because you can use apportionment problems baskets, one called Alaska gas income, one called Alaska oil income. There would be some fairly arbitrary lines drawn there, but, again, some people have said that that's true of the three factors as they exist.

The problem is going to be is if the corporate income tax has changed dramatically or changed at all in ways that make it unclear, whether, in fact, an article is being taxed under the new corporate income tax or the new SCIT, a new tax and is also having a payment made on it.

So, what we have is we have --

unlike the other system which you basically -- you know, at the point which the parties agree that the -- that that particular PILT will no longer apply and the State would be free to impose a tax or if taxes are still in place, those taxes would apply. In this situation it's a little more restricted. Basically at 30 years and then again every five years, which at least according to the calendar most of us think of, there's two more elections, so one 15 years at before the end the contract; one ten and one five years. The parties can elect to move it to restrict the payment in lieu of corporate income tax just to the project itself.

If -- and then, at that point, the tax -- the tax -- excuse me, the tax that's asserted on oil would now be under courts, under law, would not have anything to do with the contract. But the one right we did reserve is if the producers argue that that tax is taxing oil for which it is or some substance or somehow getting to income derived from the same things that it is already paying a payment in lieu of tax on, then an arbitrator can say you don't have to pay that payment in lieu of tax. So this is an area where we have built in the rights that we think we need when we agreed to only have fiscal stability on oil go for 30 years, be for the period of sort of initial -- initial FT those kinds of things. On the other hand, it is -- it is a far from -- it is a lot harder -- more difficult problem to solve than it was for the property tax and for the production tax.

Let me get into -- I'm going to skip ahead now to Article 38, which may be something that Bob was going to cover, but it's a very, very important part of this particular -- of the discussion of corporate income tax. Article 38 has -- what are called interpretive provisions. You need to kick me if I'm getting way out of my league here by pretending I'm an attorney.

But basically the article talks about presumptions and construing exemptions, and the fundamental idea here is that no doctrine, rule or principle of law or tax law that would create a presumption against or deference to any party. I guess I should have put a verb in there, but there is no thing.

The notion here is that this is

a -- we are now in a contract, and so the two parties are equal in that contract, and if there is a dispute, that dispute will be decided on the merits.

Now, under tax law, there is a different set of presumptions that apply.

Typically, and I'll focus in on the corporate income tax here, but this also applies for example, to personal income tax, that -- your federal income tax that we all pay. It is self-reporting. We say, here's what my income is, here's what my taxes are. The Commissioner, Commissioner of Revenue in this case or the Commissioner of the IRS in another case, can assert otherwise. They can look at it, and they can, say, No, here is what we think the facts are. And the Commissioner's assertion is given deference. Essentially it switches, and if you look through law, there's lots of cases that end with, yeah, the Commissioner met his burden. The Commissioner showed this, the Commissioner showed that; and the appellant does not get that deference in those cases.

What this is saying is in general in this contract, we're going to have two equal parties and issues between them will be decided on the merits. The one exception to this is here in the corporate income tax section. Where we have. I apologize, I think my spell checker got away from me here. There's a couple of words that say something different here in the last line.

But basically what this says is that any presumption, created or arising under the laws adopted in Article 19.1. In other words, when we go out and we adopt the whole corpus of federal law which included all the assumptions in it is also adopted as part of this contract. So, this is different from what's set up in 38.3. Except that the State's determination of a tax under the laws adopted in Article 19.1, its interpretation of a law, or its immaterial allegation of a fact relevant to the determination of a tax is neither presumed correct nor -- and here you need to correct this, it should say. It should say, "Nor entitled to deference, not entitled to defense."

The notion here is that for certain aspects of this relationship between a commissioner and a taxpayer we are stepping back from the presumption that the Commissioner can -- can assert a tax and therefore is entitled to deference. And, instead, we are on the merits. But what we are not trying to do is dismantle the entire federal system that's based on that premise when we go and bring in those federal rules.

So, that is what -- that is what -- how the -- how the contract deals with the corporate income tax, and, like I say, it is -- if you look at the various graphs we have here, this is the second largest piece of the revenues that we will be bringing in under the Stranded Gas Act.

Good breaking now, Bill?

COMMISSIONER CORBUS: We have two -- we have two tax questions which maybe you could answer first, and then we'll take a break for ten.

MR. DICKINSON: Sure.

To make sure everyone is tracking on the terminology please explain "waterfall." I promise to do that when we get back from the break.

The 30-second version is that there

are a whole series of obligations throughout this contract, and what Article 22 does is bring them together into two sets of transactions in which there may be netting -- on the one hand they can be looked at as a way of convenience of taking a whole lot of set of payments and -- and collapsing them into one set of payments. On the other hand, it can be looked at as a method of security interests and making sure that folks get paid when there are offsetting claims. But I promise if you stick around for another couple hours, when you're done, you'll know exactly what we mean by "waterfall."

And, actually, the terminology for a while was "silos," and for some reason we switched from "silos" to "waterfalls," but if you find old documents, you might see them referring them to silos.

Does the upstream cost allowance not cover the cost of impurity disposal? If not, why not?

Well, you know, I just stopped at Article 19, and Article 20 are cost allowances, so maybe I'll answer that question when we get to Article 20.

MR. LOEFFLER: I want to add one thing. You may look at the language on the screen and say that an immaterial allegation of a a fact is not presumed correct. That's -- that's nothing. It's immaterial to begin with. So the inference is that a material allegation of fact still is presumed to be correct. It's not a typo. It was, for some reason, what the companies wanted. It's curious when you think about it.

That's all I want to say.

[Break]

COMMISSIONER CORBUS: Would you take your seats, please?

We're going to shift gears slightly on you and have Bob Loeffler make his presentation, and if we have time at the end of the day, Dan Dickinson will finish his. Otherwise, he'll finish up on Saturday morning.

Mr. Loeffler needs to catch a plane here, so we need to get him -- get his work done today.

Bob.

MR. LOEFFLER: I will deal with various articles at the -- towards the end of the contract, including dispute resolution, force majeure, some other things, traditional challenge that I think people are interested in.

I apologize in advance for the length of the dispute resolution slides. There are, like, 50 slides. Three of those are duplicates, so it's a little less than you think.

There's a measurement article, and as you've appreciated, I'm sure, by now, there are all sorts of volumes and quantities that have to be measured for application of various PILTs and things under the contract. And Article 24 deals with that. And, generally, what it provides is that the same measurement methods that are used among the producers to allocate their shares of streams that come out of the fields should be used in dealing with the states -- the State.

And -- and beyond that, we want to be sure that we get the same composition of gas and hydrocarbon liquids that come out. Our share is measured not on the basis of heating value, but it's the same physical composition of gas and hydrocarbon liquids, and that's what that provides.

If there is a problem with a measurement, it is fairly common practice that the adjustments are made prospectively, so you trim up amounts of gas in the future to compensate for problems in the past, and that -- the clause follows that arrangement.

Unless two or more producers get a monetary payment, in which case the State also will get one.

Here we get to quite an interesting article, and it deals with any judicial challenge to this contract, constitutional or otherwise.

We have a question on this, and I'll answer the question in the context of discussing this article.

If the validity of the contract is challenged, the parties cooperate in defending the contract, the Stranded Gas Act, and if there's an early challenge, and, you know, according to hearsay there may be an early challenge, there's a right of suspension given the mainline entity. It can stop working. But there's a big qualification on that right of suspension which I'll get to in a couple slides. And you'll note when we go back, that the right of suspension is given to the mainline entity, but there are a lot of other participants, there might be a GTP entity, there might be a Point Thomson entity, and so the others -- if the mainline entity starts the process by saying it wants to suspend, the others can suspend.

A couple things are not suspended. Payments under Articles 14, 15, 17, and 19 are not suspended. They must continue. And then the suspension terminates after an order deciding the judicial challenge or the mainline entity terminates.

But here's the limit. It's -- it occurred to us that it would make no sense to enter into a contract which provided things to happen as they do under the work commitments clause right-of-way once the contract is signed, and then have the contract immediately suspended.

So, we put in or we negotiated for the clause which put a limit on the time for suspension. In other words, the mainline entity cannot suspend operations until 15 months after the effective date of the contract, the conclusion of project planning which is anticipated to be a year and a half period or so, or the project entities have spent a total of $120 million of new money to advance the project planning stage.

A question was asked: Well, what's going to happen? How long will a court appeal take? Will it go to the Supreme Court right away? What's your anticipated timeline? Questions like that.

My understanding is the Administration has proposed legislation that would have the case be taken first by the Supreme Court of Alaska. The Administration wants -- if there's going to be a challenge, wants it to be broadly decided quickly by the highest court of the state of Alaska.

There are various estimates some -- there are lawyers in the audience, but they can provide their own estimates, but a case of this importance we hope will be decided within a year, a year and a half from the filing from the pleading that initiates the case. So we provided for most of that period that the mainline entity cannot suspend its work until the expiration of the three of those. And that's the thinking behind that.

There's a sort of notice protocol. If the mainline entity, after the 15 months or 125 million, et cetera, does want to suspend, the State has the option of putting money into the project to continue the planning, the last months of the planning exercise, and there's a limit on that until project planning is concluded or the State has funded an additional 45 million.

The State would get credited for the 45 million, but you might be in a point where you're a couple months away, for some reason the mainline entity invokes its right to suspension, the State does not want to lose the momentum on the project and could advance the money. That's what the $45 million clause is intended to do.

You can see that the State will be reimbursed for any money it advances if it chooses to advance money.

Here's a -- part of a clause that relates to a question that was asked. If a judicial order holds any part of the Stranded Gas Act unconstitutional or invalid, or leaves it just uncertain for future decision, like the issue is not ripe yet for the court to decide, any participant in the -- and the language of a participant, remember, refers to a company, not the State -- can terminate its participation by providing notice to the State and it's released.

So there is a unilateral option here of -- by one or more of the companies to get out of the contract if the court invalidates the contract.

If the Supreme Court of Alaska, hypothetically, ruled that the contract was -- was void, it would seem that the effect of that would be to release the State from the contract, too. Because you couldn't enforce a void contract. But it is, as written, a unilateral right, and that was, again, negotiated.

The contract administration and notice was an interesting discussion. It really revolved around the point that the companies wanted a single point of contact, official point of contact for the administration of the contract. And so what the contract provides is that a state administrator will be appointed by the Governor who will be the single point of receiving or issuing official notices under the contract.

It's to avoid a situation where you

get an audit notice from one department and then an overlapping audit notice from another department. It's incumbent under this provision for the State administrator to work with the Commissioners and the Governor's office to distribute notices that are received to the appropriate people within the state government to do them. And, also, if the State wants to initiate action by sending a notice under the contract, the departments would work with the administrator.

Assignments and additions. Recall that there is a list of properties which I think is Exhibit D to the contract and there's a series of provisions that deal with what happens when those are switched among affiliates or among parties to the contract what will happen of adding new properties not on Exhibit D to the contract and also whether the project entities will come on to the contract and be bound by it.

The first point is just a transfer or assignment of rights in a lease or a unit to an affiliate of another producer happens by notice to the Commissioner. If it's assigned to another person, not an affiliate or another producer, then that has to happen, as it does under existing law with the approval of the Commissioner of Natural Resources.

The producers are obligated by the contract to add to the contract when they're formed, the midstream element, that's -- each of these LLCs is their forum, so they become bound by the contract. That says the same thing, each assignee will be deemed a participant under the contract. And if the rights are decided by the rights of the assignment between the original producer and the affiliate, the original producer participant retains whatever rights it doesn't assign.

Now, there was a question of some really equal treatment in terms of new properties. The protections of the contract are afforded to the properties that are listed in Exhibit D. A producer may want to add a new property to acquires, but we did not want to create a situation where a producer would have a benefit in bidding or an advantageous position in bidding for or paying for someone else's property as against someone who's not a party to the contract. So what you have is this clause and it's got -- it's -- it's actually not constructed right on the PowerPoint, but it is constructed right in the contract.

Additional leases or units can be added by the producers to the contract. That's ones not listed on Exhibit D.

But they're removed from the contract if they don't deliver gas to the mainline within either 15 or 20 years, depending whether it's a State or Federal lease. And a law providing for a uniform upstream fiscal contract is provided.

And the law or one draft of the law for a model upstream contract is attached to the contract. It's slightly out of date, but it contains the essence of what the State would propose. And the idea there is that any other oil company could get the benefits of the fiscal contract, the core benefits, if it agrees to commit gas to the project up to a volumetric limit of 70 -- I think it's 70 trillion cubic feet. And it's the idea we want to encourage everyone to come in, develop the gas resources, put them under the contract, but it's -- the producers' right to add more leases to the contract is dependent on this law being passed.

Again, just to close that off, the idea is to create a level playing field between people who are part of the contract and people who are not part of the contract and getting the benefits of the contract.

Force majeure, I turned to my law school copy of Black's Law Dictionary, a force majeure is an event or effect that can be neither anticipated or controlled.

And they're standard in international and national contracts. You don't have to perform if a force majeure occurs as a suspension. That's the basic idea of force majeure.

Usually there are a list of things that sound like they're from the Old Testament. They don't include locusts and plagues, but they include acts of God, floods, epidemics, wars, and things like that, and it's a pretty standard list we have.

But, first of all, the contract requires that a force majeure event causes a party to be unable to perform or materially affects its ability to perform a contractual obligation or its ability to satisfy the diligence standard of the work commitments clause. But, on the other hand, it must be beyond the reasonable control of the party.

So, if you can -- could mitigate it by reasonable steps, it's not force majeure.

And here's what I meant. The force majeure events, and there's a list, are acts of God, epidemics, fires, hurricanes, floods, earthquakes, war, riot, civil disturbances, labor disputes, unavoidable accidents. And it also includes laws of federal, state, Canadian or other governmental entities or unreasonable delays or failures to act by such entity.

And just dwelling on that for a moment, it is conceivable that you could run into scenarios where the Canadian government could enact legislation or rule in a way that would preclude this project. It's, I think, unlikely, but the force majeure clause is intended to deal with that, or a government agency refuses to grant a permit that's necessary for construction.

It's fairly standard how this operates. There has to be notice. If you want to claim force majeure, how long you think it's going to -- state how long it's going to take. When it's over, you've got to say how long it took, what the consequence of it was, and what relief is sought. Normally, the relief is an extension of the contract by that amount.

We -- force majeure, again, dealing with the early years or early months of the contract we had force majeure cannot be invoked until early in the contract, specifically, not until the earliest of 15 months from the effective date, conclusion of project planning, 120 million has been spent to advance project planning.

Again, the idea is we don't want to sign a contract and then, poof, it goes away because of the judicial challenge or force majeure. So we've created a -- a -- initial period of time in which force majeure can't be invoked.

There's an obligation on the party who claims force majeure to act with reasonable diligence to cure the force majeure, but the reasonable-diligence clause also has an exception that it does not require a party to pay off a dispute, regardless of the merits of the dispute.

Because what you're dealing with in this language is intended to deal with is a party who potentially would have unequal bargaining power against the project because they could just shut it down. So it's a little way of leveling the playing field. And that's what the exception to the reasonable diligence clause is intended to do.

The usual consequence of force majeure, an extension of time equal to the duration of the force majeure. Recall when we were discussing term yesterday that I pointed out that there is an overall limit on how long force majeure can operate to extend the contract. And that overall limit is 45 years.

There's no interest or penalty during this time. The State cannot invoke a law of the state as a force majeure event preventing the State's performance of the contract.

So, if the Legislature chose to forbid the State from doing something, the State would not be able to say, hey, can't perform because we're barred from performing.

And no party -- any party cannot act with the intent of causing the force majeure.

Dispute resolution will take a lot of time, but I'll try and do it reasonably fast. It's a long, complex article, but let's start with the first principles.

The first principle is that you had to have a way of resolving disputes under the contract, producers were trying to create a clean slate. They wanted to use what is really quite standard in a lot of contracts these days, arbitration. In almost every case they wanted arbitration to be the -- the dispute resolution mechanism and the only dispute resolution mechanism under the contract. And, interestingly, they took a long time -- an inordinately long time to present us with what they thought the dispute resolution clause should be. Because they had some differences among themselves on what should be.

The dispute resolution clause is intended to be the clause for resolving disputes between the State and the companies under the contract. It is not applicable to disputes between the companies themselves. It's between the State and the companies.

Article 26 -- let's see -- has a

few basic principles, but the details are contained in Exhibit C. The awards rendered under -- by arbitration are final. They can be enforced in any Superior Court in Alaska. And a judgment entered into -- in an Alaska Court could then be enforced in any U.S. state court with jurisdiction. And that, basically, follows the full-faith and credit clause of the United States Constitution.

The substance of dispute resolution is governed by Alaska law. The procedure is really determined first by the United States Arbitration Act and the provisions of the contract. If there are disputes that relate back to the contract if the contract terminates, the dispute resolution procedures continue to apply. And if an award made in arbitration is not picked up and paid off in the waterfall which Dan has briefly described, it can be -- you can go through the court process to collect it.

Here we go to Exhibit C.

There are three different kinds of dispute resolution within the Exhibit C, and there are variations even in mandatory arbitration, which I'll get into.

For most, but not all disputes, the first thing you have to do if there's a notice of dispute is you have to go into a mandatory, informal, amicable resolution process. When that's over, that's about 120-day period -- it's a very quick period -- you go to mandatory arbitration, and then there's an option to go to mediation. The general idea is that the informal step is a step where senior representatives of each side meet together quickly and to say, hey, is there a way out of this, you know. The little people who administer the contract don't see the big picture. Obviously, we big people do and can we find a way out without going to arbitration.

I'll get into the actual process.

Mediation, as many of you know, is a process by which you bring in an outsider who sort of listens to one side and listens to another side and suggests questions which are designed to bring the parties together.

Arbitration is the equivalent of a court process, but it's done not in court but through or before an arbitration tribunal of a number of neutrals or principals.

Now, let's go through each of

those. I've talked about dispute resolution under Alaska law. I'll come back to that in a minute. And I've talked about all that. Let's see.

I know what the problem is. Interestingly, pages 88, 89 and 90 are the same -- and the computer has jammed.

Here.

What's a dispute?

A dispute is about anything under the contract. A dispute means, a dispute, matter, controversy or claim between the State and a participant coming out of the contract articles or exhibitions including interpretation, construction, performance, enforcement, privileges.

Either party -- any party can give notice of the dispute under this broad definition.

There are a number of -- of places in the contract where for matters of emphasis the clause said if you're unhappy, you could give notice of the dispute, but that's without prejudice to this broad definition of a dispute.

There were a number of potential

disputes where we did not want to waste the time, in our view, to go through an informal step in getting to arbitration. The idea was that there was a need for a time, an expedition here that if the State chose to bring a dispute of these particular -- one of these categories, that it wanted to go right to arbitration.

For example, if the State wants to terminate the contract under the work commitments clause, by definition, the State is very unhappy with what's going on there, and we wanted to go right to arbitration. On expansion, same thing.

Capacity, management. As I recall the clause that's involved there, if there's an allegation that the state has disclosed confidential information, under the capacity management clause, we wanted that determination whether we had improperly performed right away. We didn't want to go through the in- -- informal step.

And then the last category, 14 in Exhibit P, are the same in disputes under the new or hopefully new PPT PILT. We wanted to go directly to the formal step of arbitration. Because we might have an informal process in the

Department of Revenue, we didn't want to have a second informal process before we got to dispute resolution by arbitration.

Quickly, on the steps of the informal process, you provide a notice, you say what your issues are. Two weeks later, roughly, the receiving party must respond with its position. Within two months of that, persons with authority -- I think the term is senior representative -- each party decides who its senior representative is -- will meet and try and resolve it in good faith.

And then if that doesn't resolve it from 120 days of the -- that's a pretty short time for the legal process -- of the original notice, the arbitration process may be invoked.

And whatever happens in the informal step is not admissible. Generally, that follows the settlement privilege, unless admissible for other reasons. There might be documents that were constructed that would be discoverable for other reasons and they would be admissible in the arbitration.

Again, you're given notice. This tells you, generally, what you should put in the notice.

I'm going to get into baseball arbitration, because there is a category of disputes that is subject to baseball arbitration. I think, as most people know, baseball arbitration is where each side presents a best and final offer and you pick between the offers. The arbitration panel picks one or another. Doesn't add them together and divide by two or two-thirds or whatever.

Then there's reply time.

There's this concept of a multi-participant dispute. They're a single -- if you think about all the controversies that could arise, there might be controversies between the State and an individual participant. I'll give you an example. SCIT, State corporate income tax. As Dan said, the corporate income tax arises from quite specific factual circumstances of each company, and normally those are litigated. Today company by company, you don't to a SCIT litigation against all the companies. Typically, you have a taxpayer dispute. So that might be an example of a single participant.

There are other areas which are multi-participant disputes that might involve everyone who's a participant in a unit, and so the contract draws a distinction between single and multi-participant disputes.

You've got to state your claims before the tribunal is selected. Sort of good case management. After that, you could only add to what's before the tribunal for good cause.

The advantage of a multi-participant dispute is that the relief can be granted against everyone in the dispute, so you don't have to proceed individually.

Here's a list of multi-participant disputes. It might be common position of the companies, one where the -- any party seeks to terminate the contract, capacity expansion, Point Thomson, administrative termination -- that's similar to the second point. Confidentiality, that could be individual or it could be common, or people say this is -- really is a big dispute, everyone should join.

Participant not involved in the dispute may say, hey, this is really a multi-participant dispute and away you go. And the tribunal has to decide that quickly. It's like an intervention.

Generally, except where the State seeks to terminate the contract, the State can only pursue disputes individually against the participants.

Baseball arbitration, I've spoken about. Baseball arbitration is quick. The disputing parties have to simultaneously exchange their final offers within 75 days after the tribunal is selected.

Here is an interesting thing. BP and Exxon, if they have disputes of the defined categories, they have the right to baseball arbitration. ConocoPhillips doesn't. It can suggest it, but it doesn't have the right.

And it's a dispute over a numerical amount whether a producer may be assigned an interest in a property or adding in an individual person. You might infer -- and I won't say if you're correct or not -- that there's a difference in companies about their views of baseball arbitration from the way this clause is constructed.

However, any dispute under the

new -- hopefully new PPT must use conventional arbitration. Even if it's a dispute about a number.

All other disputes, except the ones listed on that slide, go to conventional arbitration. And conventional arbitration is -- is like a court case. The arbitration panel comes up with a result, an award, and a rationale for the award.

Unless the parties agree, you have three arbitrators, they -- we try and select the arbitration panel within 75 days. If we fail, you go to CPR. Used to be named the Center for Public Resources. It's called the International Institute for Conflict Prevention and Resolution now. It's a well-established, well-used, well-respected body.

In fact, generally, if you went to the model CPR rules, you would see much of what you see in the contract.

Arbitrators have to be independent, impartial, knowledgeable, not employed by any of us for ten years, and must be bound by the procedures.

If they have doubts about their

impartiality, they have to disclose those. We cannot talk individually about the case to any arbitrator or candidate.

You can challenge the potential appointment if you have doubts about impartiality within 15 days of the appointment or learning of the doubt.

CPR decides the challenge.

There's a replacement procedure.

If you believe for some reason that the arbitration panel doesn't correctly have the case, then you have to bring that to the tribunal first.

You have to -- if you have jurisdictional challenges, you have to bring those very quickly too, because you want to get those issues out of the way.

You waive defenses of sovereign immunity, and immunity to judicial process.

I should say that it's interesting that there have been a number of arbitration clauses in state settlements and state contracts. The State -- not very many times have those been invoked. My understanding -- I could be corrected on this -- that it's worked out quite well for the state. I know that there have been a number of arbitrations among the North Slope producers not involving the State where occasionally a bizarre result has occurred, but -- and the one I have in mind is the original North Slope arbitration about the value of gas in which the arbitration panel came out with a very high value of gas when there was no market for the gas. It seemed like an oxymoron.

But the industry believes strongly in the value of arbitration as impartial and faster and maybe costing less than court process.

The tribunal can do sort of anything within the normal range of litigation process and structuring the procedures for a dispute.

It can take evidence. It can have expert witnesses. It can order particular order of witnesses. It can control discovery. It's given a lot of latitude.

And then there's this initial pre-hearing conference in which the tribunal calls the parties in and decides how it will proceed.

All of this is pretty standard.

It's just the way in which the process goes.

I mentioned this earlier. The United States Arbitration Act governs arbitration, and that's -- sets a procedure, and it sets limits on how an arbitration can be challenged. In fact, arbitration -- awards by tribunals, unless there's a very limited set of circumstances about fraud and duress, must be enforced. There's not a second level of review from the arbitration tribunal.

So when you think about it compared to what you may be used to in court, where there's the Superior Court, the Supreme Court, and back and forth, and it goes -- this is a -- pretty much a one-step process.

I'm ignoring the informal dispute resolution. But when it went into mandatory arbitration, you've got your tribunal. The tribunal decides the case. And there you are. And then it's enforced in court. It's not reviewed in court; it's enforced in court.

The tribunal is given the power to grant any relief within the scope of the contract. That's provisional releases, conditional, like a temporary restraining order, preliminary injunction; specific performance would be an injunction.

The remedies must be consistent with the contract. And I pointed out yesterday, I think it's Section 38.2 or 38.3 that has a limitation on liability. So they can't override the limitation on liability in the contract.

Generally, the tribunal will decide what discovery is appropriate given the nature of the case, and there's a graduation of levels of discovery depending on how big the controversy except for PPD disputes, and I'll show you what happens there. Each disputing party -- how the expert works, limited predocument productions, that's without additional provision of the tribunal, and prohibited from taking depositions on written questions.

And so you could see that you have very few depositions if it's a minor dispute, or two categories of minor dispute, five depositions for other disputes unless good cause is shown. Oral depositions of expert witnesses. But then on a production tax dispute, we draw on our experience. And production tax disputes until now, PPT or PPT PILT disputes involve a lot of money and are big cases. And we'll just leave it to the tribunal to establish the discovery. There can be protective orders for confidentiality, and if you don't comply with the orders of the tribunal, the tribunal could literally enter a default judgment.

The next stuff is sort of lawyer stuff about how you do your pleadings, and I'm going to skip that.

Interim relief I've talked about; it's preservation orders. It's a little beyond the scope of my imagination to see why this contract would involve the sale of perishable goods, but companies wanted that. We didn't have a problem with it.

Again, in the interest of expedition, disputes submitted to the tribunal should ordinarily be resolved within six months of the initial prehearing conference. And the tribunal is asked to issue a final award within a month thereafter. That's very quick based on historic practice and precedent.

And it's a best efforts. Everyone has to agree to modify the disputes.

Except in baseball arbitration, the

tribunal has to explain how it reached the result. It's like a decision by a court.

We didn't want a black box result saying you win, you lose, except in one case.

There can be temporary or meanwhile in the meantime awards. There can be a dissenting opinion, but it's not part of the award, meaning it doesn't go to court.

And then you can request clarification or interpretation of the award.

And it's final and binding, and it goes into force. If you ask interpretation, it's not final until you get the clarification or interpretation. And this may or may not be controversial to some, but an award is an award on the specific case that was before the tribunal. It can't be cited as precedent against any participant not a disputing party.

Now, it's sort of interesting when you say it may not be cited as precedent. What that means is it's not binding on anyone who wasn't a party to the case. In my view, you still could cite the result subject to certain limitations and say the reasoning was persuasive, but it wasn't binding. So, judges and arbitrators sometimes think it's valuable to see what someone else who's faced the same issue has decided and how they've decided it.

So you can still argue it's persuasive reasoning, but it's not literally binding.

The last part of the dispute resolution is settlement and mediation.

It's got to be done by agreement, it's got to be someone who's not part of the tribunal. CPR has a mediation process you use. Like in all settlements, the information exchanged is not provided to the tribunal.

That is the whole set of the dispute resolution. It bears careful reading. It's -- it's a complex thing. It is a substitution for the court process. It's designed to be impartial. It's designed to be quick, and given the long life of the contract, it will probably be invoked one or more times.

There's a set of interpretation articles which I even hesitate to go into, but I'll mention them briefly.

This is one of my favorite parts of the whole contract. Some great wordsmith wanted us to define how the word "and" is used. So here's the definition in the definition of how the word "and" is and how the word "or" is, and some poor young lawyer in my office had to go through and look at all the "ands" and "ors." I hope he got it right.

Article 38 is a number of principles. Now, the first one invokes the parol evidence rule, which means the contract stands on its own. The records, the parties have created notes of the negotiation, what one party said to another, all of that is barred. You can't use that. You interpret the contract as a new document; that's the parol evidence rule.

How the parties perform the contract after it's executed is relevant, but that's not the same thing as saying, my notes of what a particular clause meant or the company's lawyers' notes are admissible or relevant to the process. It is a standard rule and here it is restated in the contract.

You have to give notice under the contract. The third point is something Dan talked about. It's the idea we're entering in sort of a new world, a contract world, not a world under where there are presumptions or preferences that were established under State law, and that's what the third quirky dot does. And I love the last one. It's like the parol evidence rule, except for what was said in the contract, you can't rely on any other statement, representation, warranty or agreement of any other party.

So, everything I've said here is irrelevant to the interpretation of the contract.

Again, some fairly standard clauses. Because the contract is the product of the parties' joint efforts, it will not be construed against any particular -- you cannot find a lawyer who would claim to have written this contract. It's the product of a lot of lawyers and a lot of back and forth.

Headings are for reference only. They don't have interpretive value. The last clause, if we incorporate as we do in various points the State statute has a particular date. What happens after that fact is not relevant.

You can have amendments if all parties sign. Exhibits are part of the contract. Attachments are not part of the contract legally.

They're for reference or illustration purposes.

There's a set of reps and warranties that everyone's entitled and authorized to do. The necessary corporate or State action to execute. And if the Alaska Supreme Court determines the contract is not valid, there's no liability as a result of that.

There is a slide that did not make it in the package, and I'm going to give you the content of it.

If you look at the very end of the contract before all the exhibits, there's an acknowledgment, and there's an execution.

Really, execution in the sense of signing the contract occurs twice. The first time it occurs it has no legal effect, but when we get done with the whole contract, the parties conditionally execute the contract, but it's not binding because it's got to go through the legislative process. Then after the -- assuming the legislative process comes out affirmative, then the parties make a final and binding execution of the contract.

The nonbinding execution is really a way of the parties acknowledging that they're done for the time being with the language of the contract.

There are conditions to the first conditional and nonbinding execution.

One, the Legislature has to give its authorization pursuant to the Stranded Gas Act, and that there has to be some amendment of law, amendment to the Stranded Gas Act to authorize the contract as it finally was negotiated.

This last slide, 41, deals with -- again, was a particularly difficult problem. In the royalty area and some other areas, the contract may have the effect of amending certain settlements or at least the operation of those or agreements or notices or interpretations. And so what the Article 41 says is that if there's a dispute between the contract and another document, we'll attempt in good faith to work that out, then the contract will control.

And there's an amendment through the operation of the clause of any term of lease agreements or whatever that's necessary to conform to the substance of the contract.

The sovereign power and state law

clause, again, part of Article 41, is intended to make sure that the State is protected in its right to enforce its environmental laws. That its police power agencies and laws are not affected.

So, the State reserves the right to enforce its criminal laws, reserves the right to enforce its environmental laws, and the fact that it's an equity participant in the project is not intended to and does not affect the State's rights under those laws.

And that is what I intend to cover, Bill.

I have a couple questions. I don't know if you want to take a break or -- I may have more questions than I know.

COMMISSIONER CORBUS: We have quite a few questions here. Why don't we take a ten-minute break, please.

Thank you.

[Break]

COMMISSIONER CORBUS: Could we take our seats, please?

MR. LOEFFLER: We're going to start again, and I will answer this pile of questions, or attempt to answer what's been given to me.

Question for Mr. Loeffler: Given that No. 1, the AGPL LLC has not been finalized and, No. 2, PPT terms have not been set, why are we even considering this proposal, question mark. Aren't those two items gaping holes in the proposal? If changing any term in the proposal allows the parties to back out, shouldn't we wait to finish those two crucial matters?

The -- the Administration did everything it could to get everything ready by May 10th. We ran into a slight bump on the passage of the PPT, and a decision -- and the LLC hit a snag at the last minute, too. And I think the Administration -- Bill could speak to this better than I -- decided that we were -- had so much finished and we were really working very late on May 9th to get every piece of this agreement, and as you know, there was pressure to disclose the agreement from the court order, that we decided to put out everything we had done that was finished. The gas parts of the contract are essentially done, although there is the overall reservation that they could change.

And we decided to start the

process. It seemed to make sense to get it out and start the process of education and get the other things done as quickly as we can and brought before you as quickly as we can.

The definition of a force majeure event states in part beyond the reasonable control of a party. This seems soft. Please explain why the definition is not stronger.

We looked at a lot of force majeure clauses and they often read in exactly that language. When you get -- we've -- it's sort of a question of drafting. If you make something very precise, you're excluding a lot of other possibilities. So it's better, in my experience, to have reasonable language that you can later use to argue for particular results where more precise language may have knocked it out. But it is a pretty common term.

If the court holds what -- that party -- if the court holds that part of the stranded gas contract as invalid, it may materially change the remaining obligations. Why was the withdrawal provision written only to protect the companies and not the State?

Well, there was considerable

discussion of that point, and the feeling of the companies was in a sense they would lose potentially a lot more than the State. They would lose fiscal certainty, and they wanted to be able to reconsider overall where they would be with the loss of fiscal certainty.

There was an effort to make it bilateral, but then, as I've already indicated, there was a feeling in the executive branch that if the contract was void by the effect of the ruling of the Supreme Court, we would not need anything more than that.

Will lease provisions and regulatory disputes or issues be resolved by arbitration or under the contract? I'll give you a good lawyerlike answer. It depends.

A regulatory dispute is a dispute before a regulatory agency, and that would be resolved in the process of a regulatory agency.

A contract dispute relating to a regulatory obligation would in the first instance be decided as a contract dispute.

Lease provisions recall what I just said about Article 41, would be decided generally by arbitration under the contract. That arbitration would not affect parties -- there might be multiple parties in a lease dispute, some of whom were parties to the contract; some of whom were not. The parties not a party to the contract could not be bound by the result of the arbitration.

If we arbitrate a dispute with the three companies, the judges are chosen by average of the parties. Are we, the State, weighted three times or do we only get one vote on the judges, arbitrators, and the oil companies three? Is there any prohibition on the oil companies working together in choosing the judges? I had some discussion about this over the break. I'm going to look at that question a little more, and I'll provide an answer in writing.

I will say that in our experience, as we've worked through a number of issues in this contract, that it's reasonable to predict that the companies in some, but not all instances, are not going to line up together. There are differences even today, among the three companies on what the voting provision is, because one company or another fears that the other two will gang up on the State against it.

And those things have to be worked out.

But when you get into issues like expansion, you could -- the answers are not intuitive as to who would be voting with the State in favor of an expansion and who would not.

I don't want to -- and can't get into the details of the LLC negotiations, but there are parallel discussions and negotiations on exactly that sort of thing, but I will provide an answer to the issue of how the judge selection clause works.

The legal presumptions which say vague provisions on credits and taxes should be resolved in favor of the State under current law are given away in Article 37.3. Why? And what did the State get in exchange?

I think Dan addressed that. If he were here, I'd have him address it again. What I heard him say was that the feeling was that we are entering into a new era of a contract relationship between parties, and not the relationship of the tax authority and the taxpayer, for example, and so those presumptions should not apply.

Why the limit on the number of depositions? What if the State needs more to make its case?

Well, the limits are tied or graduated to the size of the dispute. If it's a $500,000 dispute, you don't want to burn up a huge amount of money on depositions through people -- taken by people like me when it's a $500,000 dispute. And as the size of the dispute goes up, the number of depositions go on, and you can ask for more, and in the biggest disputes which are the potential PPT PILT disputes, you go to the tribunal and you ask for as many as you need.

Dan, there was one question that I will give you and you can think about while I answer the rest. Then I'll tell you what I said.

Judicial challenges. Is there a guideline as to how vigorously the State would have to defend the contract, i.e. more vigorously than Attorney General Botelho defended State's rights?

The former Attorney General is a friend of mine; I respect him. I know nothing what he did -- I have no idea what he did or didn't do to defend State's rights.

I would say that it's really a question of judgment how you apply a duty to defend clause. I know that even in the case of TAPS there have been various feelings about what that clause means over various administrations of the Attorney General's office, but there is not really much guideline on what the obligation is under duty to defend.

What does Exhibit D represent? Is it a list of all the producers' current North Slope oil and gas lessee -- leases or a subset of that list? If Ken Griffin is here, he probably could answer it.

My understanding is that it is a list of all current oil and gas lease interests, but subject to correction by DNR.

The contract appears to be between the State of Alaska on one side but subsidiaries on the part of CP, Exxon and BP. Why are they not bound at the parent corporate level?

Again, a point that received some attention in the negotiations.

The State accepted the position that the affiliates or subsidiaries that signed the contract are those with their -- those that have huge assets in Alaska, and the size of those assets was large enough and important enough to the companies to cover any obligation of the companies under the contract.

There will be some form of coordinating arrangement between the parties to the contract and various other LLCs to make sure that all the obligations of the contract are carried through by the affiliates and entities and LLCs. That's still being worked on.

I don't recall whether the draft still has a possibility of a parent involvement in that or not. But -- but the rationale was what I said.

What value, if any, do you place on the deference the courts will give to a government entity that an arbitration tribunal is not allowed to extend? Doesn't the government just have to show reasonableness and impartiality to be granted court deference?

No. The standard, of course, varies by whatever law you're applying, but there has to be -- I'm most familiar in the federal context -- substantial evidence and not arbitrary and capricious action. So the government doesn't just have an automatically easy time with it.

On the other hand, in the tax area -- and Dan can probably supplement here, and that's not my strength. But in the tax area you have certain presumptions that have operated under SCIT and PILT or rather oil and gas production tax, and those do allow cases to be -- if the government appears to have acted reasonably, sometimes the presumption takes over in favor of the government as opposed to the taxpayer.

I think Dan will add to that, but again, I go back to what I heard Dan say earlier is that in the tax area and in other areas the companies were insistent that they were entering into a contractual arrangement with the State and that in a contractual arrangement, one party or the other doesn't go into disputes with an advantage in its favor.

Do you want to add to that?

In dispute resolution, does the losing party pay the costs?

No.

I think I lost one question.

If the 35-year term preventing a change in tax laws is determined to be unconstitutional, are the producers relieved of any obligation to build the pipeline? Also, how many years do you believe it will take for that issue to be conclusively determined if it is raised? Is there any limited appeal right to the courts that might take time? Is it arbitration first, then a court appeal?

Let me go backwards through the questions.

A challenge to the contract must occur per the legislation that the -- you enacted in court, not in an arbitration. So a challenge to the contract goes to court first. The Administration is contemplating legislation that would bring the case first to the Supreme Court of Alaska and expedite it. Our guess is that it would take between a year and a year and a half to get a ruling from the Supreme Court.

If the 35-year term is determined to be unconstitutional, are the producers relieved of any obligation to build the pipeline?

Well, if it's unconstitutional, they've lost their -- what they want is the protection of fiscal stability under the contract, and they wanted the right to step back and decide what to do, and as I've said, the contract gives them that right to step back and decide what to do, and they could be relieved of an obligation to build the contract, therefore.

This question, whoever asked this is going to regret the answer I'm going to give.

Can you give us an example of unlawful discrimination under Article 11.5 that the State would reimburse for?

I talked to one of my tax lawyers and I got about 43 cases and, guess what, some go one way and some go another.

There have been a number of cases in Alaska -- and again, Dan may know this better than I -- corporate income tax challenge, oil and gas property, 4356, 4355 in which the discrimination argument has been raised and it has failed.

So, in Alaska precedent, the State has done well on the discrimination claim, or alleged claim of discrimination. And could I think of a case? Well, maybe a case where the tax were -- applied to a single company -- more questions.

One company only would be possibly discriminatory. That's as close as I'm going to get.

But based on the Alaska precedent, it is hard to think of cases where the State would be due reinforcement for -- reimbursement -- would have to reimburse the companies due to unlawful discrimination.

Some of the cases involving other states where the Supreme Court has found discrimination have involved, for example, Hawaii where there was an excise tax on wholesale liquor, but the State exempted two locally produced fruit wines from the tax.

In Maryland versus Louisiana, a first-use tax on natural gas where credits against the tax were given for other taxes paid locally so that people didn't pay other taxes locally. The court felt was discriminated against.

Boston Stock Exchange case in the U.S. Supreme Court, New York gave a reduced rate for stock transfer taxes, if you used an in-state broker as opposed to an out-of-state broker.

Supreme Court tossed that one out. There are a lot of cases.

It's a good area of tax law.

There was one question that I'll search for that I recall about the meaning of "court order" under the contract and what about the U.S. Supreme Court and what about the high court in Canada.

First of all, a challenge to this contract can't be brought in Canada. There would be no jurisdiction of the Canadian courts.

Second of all, Supreme Court review in the United States is based on discretionary rights and on federal issues. The Supreme Court does not review a State Supreme Court's decision about State law unless somehow it implicates a federal constitutional provision.

The judicial challenge clause deals with challenges under State law, and that's for the Alaska Supreme Court to review and decide under the Alaska Constitution as fast as it can. And that's how the clause is drafted.

Next, depositions are often how one party proves the other did something wrong. How many depositions does the State get to try to prove a lack of due diligence if there's a limit? Why? Can the arbitrator allow more depositions if needed?

Yes, it can -- the arbitrator can always allow more depositions. The idea on the speedy resort to arbitration in the work commitments clause is the State will know when it invokes the speedy arbitration provision why it's seeking termination. It's a pretty serious step to seek termination of the contract. The State will have been working with the companies, will have seen their action or failure to act in the course of the performance of the work commitments clause and will use the evidence it's already assembled in that process to make a decision to terminate and then to prosecute termination action.

I think that's it. Dan.

COMMISSIONER CORBUS: We have one question here which I will answer.

Since this contract is clearly still in draft form, once the PPT, the stranded -- the Stranded Gas Development Act amendments and the PipeCo LLC are in here, and the contract seems intact, will this go out for another 45-day review period to the public and our constituents?

The answer is no. We believe that we will satisfy the 30-day minimum requirement for public notice included in the Act.

Dan, do you want to answer a question or two and then finish your presentation?

MR. DICKINSON: Sure.

Okay. I have a question here which says: The legal presumptions which say vague provisions on credits and taxes should be resolved in favor of the State under current law are given away in Article 38.3. Why? And what did the State get in exchange?

I'm not an attorney, I don't know if the question was drafted by the attorney, but I generally don't think that the legal proposition is that vague propositions are resolved in favor of the State. In fact, you know, if this stranded gas contract is approved, it will be the third time in the last ten years that the Legislature has changed how taxes are -- are litigated. We went from the formal hearing process to the Office of Tax Appeals through to the new hearing office. And, you know, I would -- I would argue that during the Office of Tax Appeals era, the State was held to a very high standard. If -- if we ever did anything that was inappropriate essentially, we lost the case, even if we argued it had no effect on the outcome.

We were sort of a -- you know, a clean -- a very high standard.

It's not that vague propositions are resolved in favor of the State. It is that when the Commissioner acting under certain authorities issues a -- issues an -- an -- an assessment, that assessment is presumed to be legally correct and the taxpayer has the burden of overcoming it.

So, I guess I just -- I disagree that -- that that was ever a proposition in law, so I -- you know, it wasn't necessarily given away. It is true, in fact, though, that we did limit that presumption, and I just simply can't as a matter of playing museum recall what and if that -- what part of the resolution that was tied to.

Okay. In the packages I'm going to

skip to what I show as Slide 51, or 50. Maybe someone else has a different slide. Apparently they're not identical.

This is a new graph. You haven't seen this one before. This isn't one of the same ones that I projected three or four times before. But it is also Table 8 from the fiscal interest finding, and this deals with the costs that are in the State's model. The largest one, by far, as you might expect, is the principal and interest that we will incur in owning 20 percent of the pipeline. Operating costs is a fairly large slug. Taxes in Canada -- taxes in Canada and the Lower 48 are also a fairly large slug.

But the right -- on the right-hand side about one quarter of the total is that light blue area and that is the UCA. That's the costs that we're going to pay for the folks who do the work to get our gas out of the ground and are ready for delivery to the GTP.

And that -- that area is included, that's what Article 20, the cost allowances are about.

What 20.1 says is that the producer -- the State will pay to the producer an upstream cost allowance or a UCA of 22.4 cents per mcf on State gas. And I want to be very clear about this, particularly when you contrast it, for example, with some of the -- some of the PILTs. This payment is only made on State gas. So, it's -- the high point will be 20 percent. It could go down to 16 or 17 percent further on. So it's only paid on sort of 1 mcf in 5. If you look at the PILTs, the property tax PILTs, those are paid on 100 percent of the gas. So, when you compare those two, it's necessary to go through that -- that calculation.

The 22.4 cents, that number is a number that stems from the 1980 settlement agreement, 26 years ago when the issue of -- of how costs would be paid in a -- in a major gas sale. Of course at that time people were anticipating, that would be 1983 and 1984, there was a number, it has inflated with time and that number is simply the one that's adopted, applied not only to the -- to the tax -- excuse me -- to the royalty gas that it would apply to, the royalty gas in Prudhoe Bay. It's also applied to other gas outside of Prudhoe Bay that that settlement agreement would not have applied to and also to the tax gas. So it goes from -- it would have applied under the -- under the terms of the 1980 settlement agreement to more than half the gas. This agreement simply extends that to all the gas.

The 20.4 says that the inflation -- there's an inflation adjustment and it is inflated with a CPI.

Existing cost allowances are not affected by this agreement. So, if there are other royalty settlement agreements, this will, you know -- this will supersede those. Whatever it says in the lease will be the case. If there -- if there's a dispute about whether there is a cost allowance in some other lease, particularly on oil, for example, this agreement is not probative of anything, that it is or that it is not. The Department of Natural Resources and the producers will continue to argue about those issues or may continue to argue. The point is, this agreement is not addressing any of that.

One of the things that I tried to do, I hoped to do more of these as I went through it, I just ran out of time the other night, was to sort of just show some calculations and, of course, when I did this one, one of my units is wrong here, so this may not -- may not, we need to make sure that at the very bottom line, it's not $64 a year, but $65.4 million a year. A slight error. As Mike knows, we accountants sort of do that a lot. Just a million dollars.

But just, again, to walk people through, understand, if you were starting out with about 4 billion cubic feet a day, 4 bcf a day -- 4.5 is a number that has been talked about, but I'll just use 4 here because originally I was just trying to do numbers that we could do in our head, you know -- 365 days a year means you got 1.4 billion cubic feet a year. A billion cubic feet is the same as a million mcf, because most of the things we have are per thousand cubic feet or per mcf. So you have a million mcf. You take 20 percent of that and you come out with about 292 million mcf, 22 cents for each of those is what gives you about $65 million a year. So that would be the effect of that and, of course, over time as the State's percentage of the gas decreases, that number would decrease proportionately as well. But the UCA will constitute about a quarter of the costs that we will be bearing.

Skipping ahead next to Article 20, which is payments to political subdivisions, again, we'll spend more time with this on Saturday, but there are three sort of quick principles here.

21.1 just says that even though the obligation is to the State, under this contract some of those dollars are directed towards political subdivisions. And as I emphasized this morning, I think if you go through Exhibit G, which is where all these are, we'll go through it with on Saturday, you will always see that there's not a mil rate ratio based in there.

So there's no payment that's ever directed to a municipality without saying the way you calculate it is you look at the mil rate that they choose to tax entities other than this project or choose for revenues that don't flow through this contract, and that ratio will apply to the funds that are available from this contract.

The second article, or the second principle that's articulated here is what happens if there's new political subdivisions that form, and the notion is that will not change the size of the pie. It will merely change the distribution of it. Particularly if you look at the map, there's an area, you know -- the unorganized borough. There's an area between when you come off the North Slope Borough, before you hit the North Star Borough, when you come down the North Star Borough, you kind of take a hard left and head east and then there's an area between there and the border, the Canadian border, which is again part of the unorganized borough. So the question is: What happens if a new borough forms in either of those areas, a new borough is formed?

The answer is the distributions will change, and as we'll go over in more detail, we believe we've set up a situation where we could have several boroughs form and they could, in fact, have some fairly advanced mill rates before we would have to go into any proration. But what happens is now, for example, on the -- on the payment in lieu of tax that is paid on the pipeline, Fairbanks -- the Fairbanks, the North Star Borough and the North Slope Borough will never be prorated. They will always get sort of their -- the full amount, again, with that -- with the mil rate fraction in there.

If the new boroughs are formed and they advanced at very high mil rates, I forget what it is, but I think it's like the 16 or 17 percent range, which are not typical of -- it takes a while to get there, I'll say, for most boroughs, there in fact you might get a situation where there simply would not be enough dollars in the midstream payment and there would be some proration.

But fundamentally what happens is as they come in, the State's take will go down, the share in the new boroughs will go up, and if the combination of all of that sometimes hits the point where the 2.4 cents per mcf is not enough, then there will be a proration.

The final point that's made in Article 21 and, again, maybe the lawyers will jump in here again, but it's called indemnification and recourse. My understanding is there's some language in there that's prompted by an attorney general's decision about what has to be in contracts. But the other principal that's in there is no third-party beneficiaries.

In particular, the political subdivisions are not third-party beneficiaries under this contract. They cannot -- they do not have the ability to sue the -- sue the producers and argue we're supposed to get more money or the contract's being interpreted wrong. That's always a matter between the State and the producers. And in the terms of the contract, then, while some of the payments are directed towards them, they don't have the rights of a third-party beneficiary.

The next article I'd like to talk about for a minute is Article 22. And Article 22 is where we find the waterfalls. Article 22 is organized into two waterfalls. One is for the producer obligations. That includes the upstream cost allowance. Basically it looks at all the obligations both to the -- to a producer that the State would incur, primarily the UCA, and then -- and then obligations from the producer back to State, and those are all put in one waterfall.

The second waterfall is for the midstream entity obligations. And, again, what those are are going to be the companies that are formed, the -- to build and own and run the pipeline, the GTP, and any gas transmission pipelines that run from other sources of gas to the GTP or possibly even directly to the main line if it were clean enough gas.

Those entities typically are also going to all have -- well, many of them require a State ownership percentage, so we will be -- we will be a part owner of those. As we go through them, I'll go through each in detail, but here's what sort of the bottom line is: At the bottom of the producer waterfall, if for whatever happens there is a period in which for three months the State is owing money to the producers, and we haven't paid, there are terms there by which the State's -- the producer can take some of the State gas and satisfy that obligation.

At the bottom of the midstream waterfall, same situation arises. If there's been a situation where the State owes some money and for three months the State has not paid, then the entity -- that midstream entity can divert a cash distribution that was bound for the State. In other words, the midstream entity is going to be paying out to shareholders or, you know, its owners, it makes a cash distribution, and if, in fact, the State owes money to that entity, before the State gets the cash from the entity, they'll just say no, that goes into the part -- it comes back into the pocket of the midstream entity.

I think an important way of thinking about this, as I said earlier, is with two -- looking at this from two possible angles. One of them is as a way of administering the -- the contract, dealing with a lot of obligations running both ways, and the second one is kind of as a set of security arrangements.

If you look at it as the obligations running both ways, what you will see is, in the producer waterfall in particular, is that all of the regular obligations are monies that the State is owed by the producers. It is the payment, the quarterly payments that the producers are going to be making as a consequence of the estimated payments for the payment in lieu of -- of income tax. There will be annual payments that will be made, the PILTs that will replace the property tax, and after sanction there will be the -- the payments that they are making for production tax on oil would be part of that as well. So you -- what you will see every month is there is a large amount, you know, typically what constitutes over 50 percent of the State's unrestricted revenues will be in that waterfall and will be directed from the producers to the State.

The only payment that on a regular basis runs the other way is the UCA, and that will not start until the commencement of commercial operations, until gas is actually flowing.

The one difference, and Bob mentioned some of these, and some people have focused on these in their questions are, you know, if, for example, during construction there were some taxes levied and we had to do some reimbursements, those would be running the other way. Those would be State money owed -- owed to the producers. And if in some month we owed that, what mechanically would happen is there would simply be an offset against the dollars that were owed the other way.

So, let's walk through this. The producer -- the first waterfall, 22.1(a), talks about the determination, and it goes through a list of producer monetary obligations. And if you look in your contract, I think it's literally about two pages. It sort of goes through every place in the contract where something could arise. A handful of those, it's going to arise every month; most of them are situations that could arise. I think when we're done it finishes up with something that says anything else that could arise that we didn't identify. So you have everything going one direction in Romanette i.

Romanette ii is the exact opposite and it takes everything that the State could possibly owe the producers, goes through and you add all of that. So you have those two numbers.

In Romanette ii, it says, gee, but the State, anytime it wants to pay any of its obligations individually, and there's a time table in there so this all gets coordinated, but they can go ahead and pay. And what that's really meant to identify is, if there is a separate entity that owns the gas, that is marketing the gas, that is dealing with the FT, that entity, that organization is probably going to be paying the UCA out of proceeds from the gas sales.

So if, in fact, we have one entity over here that's dealing with the gas, another entity that's dealing with all these payments in lieu of tax, we have ways of keeping them separate. Again, it's an option. Obviously how the State chooses to organize its finances and what sources come from those things are issues that you folks here get to decide. What we've done is set up that option.

So we can make a direct payment of state obligations.

Romanette iv says, okay, we take all three of these things. We take the total amount that the producers owe to the State, take the amount the State owes to the producers, subtract from it any payments that the State already made, you net it all out, and at the end of the day you're either going to have a positive number or a negative number.

And if you have a positive number, if the producer owes the money to the State, then they pay it. I think they've got 15 days to pay it. And if not, they're in default. It's that simple. It's a speech that we heard very often, but, you know, fundamentally if the producer owes the State money, we can go and start attaching assets. We can do the things that you can do, that companies can do with each other when they're owed money and they have security interests. So, that's very simple. It just says, if the producers owe, they pay.

You go down to C and it says, what happens if the State owes the producer? Well, the State can pay. It doesn't have to. It can. It has -- it has that option of paying. If it doesn't pay, and we spent a lot of time crafting this language, it doesn't mean the obligation goes away. What happens is some other rights slip in.

But the point that was made to us was, you know, if Exxon doesn't pay us, we have the right to go secure liens and start -- you know, can take their trucks and go put them in our garage. If the State doesn't pay Exxon, they don't have that same right. They can't come and seize, you know, a truck driven by somebody from the -- from the DNR or something.

So, instead, what happens is they have -- if the State has not paid five things, they have five options that they can carry out, and they can do any combination of those. It's not they're restricted to one or the other.

The first one, and it's the one -- is that we simply carry the amount forward. If they're owed something and -- and let's -- again, it is hard for me to imagine the situation that's going to arise in which there's going to be a net payment owed, you know, where the State owes a lot of money. It would probably be in some kind of a dispute that we lost, some kind of a situation where there's a one-time payment, and we could simply say, we'll wait, it will get covered next month. Carries forward, there's interest, it's a commercial obligation, but the State -- the producers any time can simply carry it forward and the provisions are all here for doing that.

We aren't necessarily in breach merely because they are carrying them out forward for us.

The second thing they can do is recoupment, which is a word that sort of comes along with a specialized meaning here, and don't worry, there's three or four slides explaining what that means that we'll spend probably more time than we should on.

The next thing they can do is they

can transfer the right to a producer transferee, which means they find somebody else to whom the -- an obligation is owed the other way and they simply transfer it to them. So, for example, let's say we owed ConocoPhillips some money, more than was covered in that month, but BP owed us money. Well, ConocoPhillips could basically say, okay, we're going to switch that around so that, you know, Conoco -- BP pays ConocoPhillips money, ConocoPhillips essentially sells the obligation to BP who then offsets it.

So you could simply give it -- transfer that right, presumably for value, if it's like factoring in the real world, it would probably transfer at 80 cents on the dollar, 90 cents on the dollar. All those options are open. We don't really care about them. All we're saying is you can transfer the right to the producer transferee. But there is one class of entities that you cannot transfer it to, and that is to a midstream element member. What I mean by that is, let's say we're in the mainline, you know, Exxon's our partner there, haven't picked on them yet, so Exxon's a co-owner with us. And over here in the waterfall Exxon is -- we owe

Exxon some money. The one thing Exxon cannot do -- they can transfer it to BP, they can transfer it to Conoco, they can't transfer it to the member entity that owns the -- the pipeline and then within the context of that pipeline turn around and say, okay, I'm going to try to go and take some of the dividends. The next time there's dividends, I'm going to go reach in and try to take some of the State's dividends. So, the one limitation here is you cannot transfer it to a midstream element member.

The next thing you can do is you can provide notice to the stattle. You can also provide notice to the State, and that's probably equally acceptable. Basically what's that saying is, if you are not being paid, they need to keep sending us notices saying, you have an outstanding amount. And typically what that -- the language that continues on there is whoever is administering this contract then will go and give notice to the Legislature that there is an amount unpaid, if in fact what's needed is an appropriation. Obviously, that's -- there's no, you know, that simply provides that that could happen.

The last thing they can do, and they have to have an amount outstanding for three months, is they provide notice that they're going to undertake what they can do in No. 2. So it's kind of a -- there's a two -- the way this is structured, 2 and 5 have a certain amount of overlap. But basically if three months have gone by and they -- and the State still owes money to a producer, again, I cannot think of what that situation would be, then -- then they can go on to recoupment.

What -- what is recoupment?

D here in 22.1 says, one month after that notice is due, what they can do is they can simply direct that we take a contract that we're getting paid on and we tell the person who's paying us to direct their payments to that third party, directly to a producer. And so typically, none of the commercial arrangements would change. Essentially we would simply be directing that those checks go to someplace else. That's the first option.

The second option if that hasn't worked and one month has gone by and that hasn't worked, they can then indicate that they're going to go in and do gas recoupment. Now, gas recoupment can be one of two things. Either it can be 50 percent of the payments, so you look at the payments, or you go in and you look at the gas.

Now, there's some limitations on the rest of the gas, so 50 percent is there and they can -- they can, you know, sort of essentially use that as a security interest to make sure they're being paid, but there are sales -- but there are restrictions on the other 50 percent.

What (f) does -- sorry -- what (f) does is it limits the sales of the gas recoupment to saying that there's certain kinds of security interests -- and if folks have questions, I'm going to have Bob come and talk about exactly what those security interests are -- but, basically, if we've already entered into agreements for financing of the pipeline or for, in this case for -- you know, using the gas as security for other arrangements, that those -- those need to be respected and the gas cannot be collected as a consequence of those -- of those arrangements.

The next thing that -- happens is the -- in the recoupment sequence -- sorry, we're still on that slide. In the recoupment sequence, again, the first thing the State does is they say, we're going to redirect a payment. If that doesn't work, you go on to this actual withholding of the gas or the cash.

Another limitation that comes -- that occurs then at this point is money that would be going to the Permanent Fund, in other words, that portion of the royalty payments also cannot be recouped or -- or held out. So that the State -- those portions that would flow through to the Permanent Fund, typically the 25 percent, cannot be -- cannot be recouped against, so that doesn't form part of the security interest that we're granting. And I may have used that word wrong, but -- okay.

The last two sections here are section (h) which are determination of the volumes, and (i) which is determination of the values, because obviously when gas is being withheld to satisfy a dollar amount, you have to come back and say, okay, how much per mcf does that amount to? I haven't gone into the details of those, it covers several pages, because I personally think at this point in the waterfall I think this is not -- this is not something that is going to be happening. Nonetheless it is something -- it is in there and it deals with -- well, it is not -- at least as we look at the numbers in random modeling, it didn't appear that there would be a situation that this could occur unless it was sort of a judgment that came truly surprisingly out of nowhere.

Moving on, you have 22.2, which is essentially that same waterfall, the same -- a lot of the same principles, but now it's -- it has to do with the midstream entities. All the numbering gets screwed up. It's totally different, because we start out with a different (a) which says, gee, those impact payments, Article 18 that we talked about earlier, those are also not part of the waterfall. Those impact payments are going to be made to the State no matter what. And if they're sort of an offsetting obligation, folks cannot -- someone with that obligation who thinks they're owed money cannot reduce their impact payments. So, the first thing that happens is those impact payments are taken out in section (a).

Section (b), it's going to look exactly the same. You start out with Romanette i you sum all the obligations that the producer owes -- excuse me -- the midstream entity owes and typically what those are going to be on a monthly basis are going to be the payments in lieu of tax, the property taxes, the annual property taxes, the State midstream monetary obligations, anything that we would owe the State monetary -- the State midstream entities, and typically that will -- there will not be anything. Those are going to be all -- extraordinary events, things that happen, judgments, recouping of -- of -- recouping bad word. A settlement of a tax amount, an increment, something like that.

No. 3 allows the direct payment of the State obligations, although, again, that's perhaps not so meaningful in this context. And in Romanette iv, net monetary obligations. You just net it all out, see whether it's positive, see whether it's negative.

If it is a payment that is owed from that midstream entity to the State, again, it's made; if it isn't made, the State can go start attaching assets. Of course, in this case we'll want to leave 20 percent of the assets we're attaching behind, because we'll own them. But, basically, as a commercial matter, there will be an entity that will owe money and we could do anything we would normally do to collect money.

On (d), deals with the opposite situation. What if there is a State payment that is owed to that midstream entity? And the answer, just like before, is the State can pay, but it's not under an obligation. If it doesn't pay, it's not in default. It is simply -- there are then options, and the option which we think -- again, you know this is pretty unlikely, but the option that would occur is you'd simply carry the amount forward with interest and it would be paid in a later month.

The second thing that can happen is you can recoup against distributions, again subordinate to the security interests. And, again, what that's saying is if -- and I'll just take an annualized example, but if once a year if the midstream entity distributes its profits back to the individual shareholders and everyone's going to get -- the State's about to get 20 percent, let's say a million dollars is being distributed, but we owe the midstream entity $100,000, before that 200,000 was distributed, 20 percent of a million, they'd say, wait a minute, nope. We're going to hold back 100,000 of that and only give you 100,000. Of course, the State in some sense, 20 percent of that is just paying itself.

So, again, subordinate to security interests, if the State has already pledged that cash flow stream, and quite typically it will. I mean, if we go out and get bonds, the bondholders are going to be looking at the distributions that we're going to get from -- from charging the tariff every month and the distributions from that. So with those security interests being subordinate, the recoupment can proceed against any distribution that would essentially be profits.

And then the third option that they have here, again, is the transfer of the right to a midstream entity transferee. And for some reason, I'm not quite sure, the Romanettes don't line up -- they also need to provide notice to the State so that if there's an amount due, the State can go ahead and take what steps, including notifying the Legislature that an appropriation is needed, to pay off that amount.

The last two articles, and Article 22 on the waterfall, 22.3, is just kind of the one that says, when all that's said and done and all these rules are defined, if for some reason one party overpays the other, you know, you meant to pay $23 million and you paid 32, here's the clause that you go to recoupment and it just goes back in the waterfall and we'll get it settled out.

And then 22.4 deals with some of the reporting and payment procedures, which just simply make this -- make this process work so that there isn't a lot of dollars flying back and forth.

I am not covering the next couple of articles which are, I believe, Point Thomson and measurement and those -- those, I think, have already been dealt with by Ken Griffin who spoke to you the other day.

What I'm skipping ahead is to

Article 25, which he may also have covered, but it's a very important article. And not so much Article 25 as Article -- or Exhibit B which is tied to it. Article 25 deals with audit. And I think there's some very important definitions that were worked on very hard. I think, again, like the folks in DNR, Ken Griffin, his background is as an auditor, so he was very, very focused on this.

The general scope is we can audit -- we can only audit, but we can audit any audit document. An audit document is defined as a document which is -- supports the information for any fiscal obligation. So, as we view it, we are limited to auditing documents which are pertinent to the fiscal obligations. On the other hand, if it is pertinent to the fiscal obligation, they cannot say -- or the person being audited cannot turn us down. So, you'll see this defined term of audit documents.

25.2 deals with audit periods and that's three years for all the fiscal articles, two years for everything else. And the three years, in fact, corresponds right now to what happens in the tax arena where the State has three years to fix the amount of tax due, which typically we do after performing an audit.

25.3 is a bunch of additional provisions. Again, not to play museum here, but when this audit article was first proposed, it was very streamlined, sort of fit everything into a single set of rules. Then we said, well, you know, these -- these audits of corporate income tax are very, very complex, and we started rewriting all the rules. And no, no, no, okay, we'll do a separate set of rules for corporate income tax.

So, the four rules here really deal with adjustments that flow through. Before I left the Department at the end of last year there was an adjustment from the IRS -- I may have my facts wrong here -- but I believe it was from 1982, and it finally came through to us. That issue was finally resolved 22 years later. And my recollection of it was by the time the claim was -- it was 11 -- I think 11/12ths interest. But what this -- what this is saying is we will not -- you know, how adjustments flow through when -- when the IRS is done auditing.

We also deal with alternative

sources for tax information. Right now we have described the plan, the payment in lieu of tax to the IRS and said, do you consider this a tax? In other words, can we continue to get information from you? Can we continue to use it -- in enforcing this contract will that be considered part of our agreement? Maybe I should back up.

The Department of Revenue enters into an agreement with the IRS that says in the enforcement of tax we can use information the IRS supplies to us. Incidentally, they can use certain information that we supply back to them, but only for the enforcement of tax. It can be used for no other purpose. And the question was: Does this contract still meet those requirements? They obviously -- they didn't give us a final determination, but their preliminary determination was that it would, and so we would still qualify to get information from them which we could use to ground truth -- or check some of the information that we were getting from producers and ultimately they'll make a final showing or a final determination. And right now what the contract says is if for some reason the IRS says no, we'll work together if there's some methods that we can get the stuff that they file with the IRS and get it sent directly to us or some other methods. We're hoping we never have to go there.

The last two clauses -- the last two clauses deal with areas in which, at least as I would characterize it, we're sort of solutions looking for a problem, and at least from my point of view, we're never able to find one. But basically what this -- you know, as I've said several times, folks are aware, you start with a federal tax return. That's the basis of your -- of your Alaska taxable income. You start with a federal basis. And what -- what we do is we only look at the things that matter to us. And so if there's something that the feds are going to look at very carefully and it's going to apply the same thing to the feds as it does to us as it does to one of the other, I believe it's 26 states that sort of base things on the federal returns, we don't reaudit it. There's no percentage in that for us. There's no point. And they -- what we have here is a clause that says, if we do ever decide to do that, we have to show good notice -- we have to have good cause.

And basically what -- you know, good cause is a fairly low standard. We can't simply treat this as a harassment tactic or something, and say we want to reaudit your entire return. We've got to say, here's why this issue would affect Alaska differently than it might the IRS. We might have a different incentive for doing it. There might be different economic reasons, so here's why we need to do it.

The same thing happens with worldwide income. Worldwide income, what we rely on are the audited financial statements in literally hundreds of companies. My recollection for one of the companies is they -- when they file their Alaska return, they have 432 subsidiaries around the world that are part of that return and probably, you know, at least -- I don't know how many countries are around the world -- but probably like at least a hundred different countries and each one are going to be audited financial statements that -- that use either the local financial standards or some other standard, but they don't necessarily affect the U.S. return, so for those we're looking at book income instead of tax income.

And, again, the question was: Are you going to go reaudit those? We typically don't, but we -- the standard we set in here is, if we choose to do it, we have to show good cause. We have to just show why we're doing it and if we go into a dispute, we have to convince an arbitrator.

25.4 has additional provisions regarding audits of Article 14, and I believe all they say at the moment is we'll do it according to Exhibit P, so that's still a little bit of a circular argument.

That's all that's in the audit article. But what's important is 25.1 says that we'll use the procedures in Exhibit B. So I'd like to take a minute and go through those, and actually in some ways they're not that dramatic or not that different. They really just establish what are some fairly normal audit procedures. I've heard some arguments that we're giving something up or we're limiting, and in general I don't believe that is the case. I think what we're doing is simply setting forth a bunch of rules that apply -- in some ways they give us express rights, but I don't think there's a limit on our ability to audit under this contract and make sure that we are being paid exactly what we are owed under the contract.

The first B.1 simply talks about the initiation of an audit. We have to tell them before we're going to do an audit. We have to say what we're auditing, and at that point we give them our first audit request and they've got 60 days to fulfill that first document request. We talk about audit scope. We talk about amendments to that audit scope, namely if they file a revision, if they file a new -- some new information with us for a tax year, that doesn't mean that we can now open up and go and audit anything in that tax year. We have to show that their -- it has to be something that will be affected by their revision. Again, I think that's a fairly common-sense view. We don't think we've ever been -- violated that; arguments have been made that we have, so there was no problem in committing that one to writing.

B.3 goes in and talks about there are going to be certain audits that are going to be under law under this contract. What that really means, it goes back to the two times --

two things that we chatted about -- that I chatted about earlier. One is, if we're taking our gas -- prior to the taking of gas in kind; in other words, if there were an audit now of gas on the North Slope pertaining to something that's happening tomorrow, that would still be under law.

The other situation is if we -- if we talked about the 95 percent rule. If, in fact, we elect to go back to law for that other use, that 5 or 6 or 7 percent -- it's 5, we wouldn't qualify for the 5.1 or greater use that wasn't dedicated to the project, then audit would also be under law. It would be out from under the contract.

The other point is -- that's made here, and this gets back to something I said earlier. A political subdivision tax is always going to be audited by that political subdivision under law. It is going to be under that ordinance or those sets of rules. Those are not bound by the contract.

B.4 is audit coordination. They have to provide a person who is knowledgeable, they have to provide a coordinator, someone to go to for documents. Same thing with document coordination. They -- you know, they have to -- basically talks about when we -- when we have to go to them, when they can deliver documents to us. We set up a special procedure, failure to provide audit documents, that basically when that occurs, we get to notice up a separate issue, go to a separate arbitration to get those documents that isn't part of the final resolution of the audit.

That's something that I think folks are aware that sometimes has been a contentious issue when we've asked for documents and haven't been able to get them.

B.7 talks about retention of documents. Basically, how long you have to keep things. What -- when notice is final, when they don't have to keep, fairly standard material there. Confidential treatment of audit documents, again, going through that this is not something you typically find in audit procedures.

Presumption of accuracy and finality. Again, the notion here is once -- once an audit is closed out, you know, can you go back and -- and reopen it? And, of course, the tricky thing is if -- if you find something -- if you close out an audit period, you didn't look at something, and then the next year you look at that particular object and you find, gee, there's been a mistake here, and it's probably been a mistake for several years, you can't go back to the period you closed. On the other hand, they can't say, aha, you approved this last year, therefore it's correct and therefore it has to be correct. So basically it's kind of the common sense point of view. If we find something that's amiss, we fix it. We simply cannot open things. We can't say we missed this for the last five years, we want to reopen the prior five years.

The conduct of the audit, you know, we will complete it, there's a single audit. When we complete it, we then issue a -- excuse me -- we then issue a -- I suppose, a -- I guess -- I'm guessing it's going to be an audit exception, but it could also be a confirmation saying, everything looks fine, we'll close out this period, they have a period to respond. We have to get a resolution. Again, if the resolution doesn't work, then we're into a dispute, Capital D, the kind of disputes that Bob talked about.

So, the audit provisions, I believe, are ones that fully give us the ability to do our job under this contract, and I think the Department of Natural Resources would also be doing a lot of this work, feels the same way.

And that's everything I had to say. I've got starting here three minutes here short of 5:00 o'clock, so I have lots of time. There will probably be questions. I guess the only point I'll make is we'll be back on Saturday. Randy Hoffbeck -- and we'll be talking about the political subdivision taxes and how the municipalities, the political subdivisions benefit under the contract.

Okay. You want to do yours or mine?

One question here: Why should we inflate our upstream cost allowance by CPI instead of an index based on gas price or an in-field cost index?

Let me break that into -- into two pieces, I -- an in-field cost index might, in fact, make -- make more sense. I don't think an index based on gas price is really going to capture -- you know, if what the upstream cost allowance is supposed to do is capture costs, you know, the kind of volatility we've seen in gas prices where a couple of -- I guess it's months ago now, we had something in the $12 range, today we're back down in the 5 -- high 5s. It doesn't necessarily reflect changes in costs. You know, I guess the notion on the CPI was that is a time-tested set of formulas and I guess one of the -- one of the notions is there are several companies that publish -- private companies that publish adjusters -- the -- including one for oilfield -- I think it's oil and gas. We could have used those. I think the notion is that CPI we were trying to get -- similar measures for a number of -- of the -- of the obligations, particularly the ones that are moving either way. So, short answer to the question, we could have. I don't think -- we chose not to.

And that's all I have for questions.

COMMISSIONER CORBUS: While Dan and Bob are conferring here, I've got a couple of administrative matters. We had a request: Can you please provide in writing a table translating all the abbreviations, UCI, UCA, CPI, et cetera, in alphabetical order so we can decipher the written materials? If you refer to the fiscal interest finding, right behind the Table of Contents, there is such a table. And if that's inadequate, please get back to me and we'll see if we can improve on that.

I just wanted to bring it to your attention that we are accepting comments on the public process. There is a -- a flyer out on the table out front there explaining where comments can be submitted via e-mail, via recorded telephone number or in writing.

Also, I'd like to thank you for staying a half an hour late --

MR. LOEFFLER: One question.

COMMISSIONER CORBUS: Yeah, I understand.

The meeting tomorrow is going to start at 9:00 a.m. and is scheduled to end at noon, and there will be no afternoon meeting. I'm going to be down at Ketchikan for the first public hearing and Ken Griffin, Deputy Commissioner DNR, will be your master of ceremonies.

So, I will turn it over to Bob Loeffler who has one more question to answer. But maybe more than one. After that, we are adjourned.

MR. LOEFFLER: The question is: Article 26.1 requires all disputes, i.e. claims under the entire contract be resolved through arbitration. How can the State attach assets outside arbitration?

Well, the position we would take is that the payment is due per the article that -- the waterfall article, and we would go out and pursue attachment, and it would be up to the party against whom this attachment is sought to initiate a dispute and ask for provisional relief to prevent us from attaching.

That's it. Thank you very much.

[Applause]

[Legislative Special Session adjourned at 5:02 p.m.]